EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 149

DATE: Wednesday, May 20, 1992

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, Wednesday, the 20th day of May, 1992, commencing at 9:30 a.m.

VOLUME 149

B E F O R E :

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MS. G. PATTERSON	Member

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THE REGISTRAR: Please come to order. This hearing is now in session. Be seated, please.

THE CHAIRMAN: Mr. Hamer?

MR. HAMER: Thank you, Mr. Chairman.

I had a discussion with my colleague Mr. Heintzman last evening and I have had a discussion with Mr. Campbell this morning concerning the matter of the interrogatories which was addressed by Mr. Heintzman, I believe in argument about the continuing scheduling of the balance of Hydro's case which was early in May. At that time Mr. Heintzman advised the Board of the series of interrogatories which had been put to Hydro which centered in part on LMSTM runs.

Now, there has been some further correspondence between Mr. Campbell and Mr. Heintzman, and unfortunately - I don't think it is necessary - we don't have copes of all that here.

We are still in the position that in our view it is necessary to have further runs conducted in order to carry out an appropriate cross-examination of Panel 10. Mr. Heintzman has asked me to advise this morning, advise the Board this morning that we are in that position, we haven't had a response to those interrogatories, and in our view we would ask to

reserve our rights with respect to cross-examination. It all arises out of the Update. If this panel is gone forever without our having an opportunity to test some of the further runs that have been conducted by Hydro, with alternative runs of our own, then we would be prejudiced, and we simply wish to raise that matter at this time.

THE CHAIRMAN: My recollection, and it may not be perfect, is that this was raised and it was discussed and there had been some discussions amongst the parties and Hydro about this and they had been suspended because of 452 and that they were going to be resumed. Has that occurred?

MR. HAMER: There has been some correspondence, there has been no meeting or resolution of that.

THE CHAIRMAN: I thought that was going to happen.

MR. D. POCH: I think I can be of assistance here.

MR. HAMER: There has been a package of, as I understand it, alternative forms of LMSTM runs delivered by Hydro. It doesn't respond to our interrogatories, as I understand it.

What our concern is, is that we need this

not only for preparation of our intervenor cases but to complete the cross-examination of Hydro's witnesses appropriately. We didn't want that just to slip by while Panel 10 sort of went over the horizon.

THE CHAIRMAN: All right.

Mr. Poch?

MR. D. POCH: Mr. Chairman, just to be clear. Following that discussion on the record, I think it was late April, early May, within a couple of days the CEG issued an invitation to a number of parties who we knew were interested in modelling to get together and come up with the definition of some common runs, the parameters of some common runs, that we could either ask Hydro to do or we could alternatively agree to be comfortable, become comfortable with each other's models, calibrated to common set of assumptions and then we could all use our own models to do sensitivities. AECL was on our list, was invited to participate in that discussion and we have had no response yet from them.

So, if my friend is here today concerned that Hydro respond, I would simply echo that concern, that we would invite him and any other parties to treat our invitations seriously so that we can get on with this.

THE CHAIRMAN: Thank you.

MR. B. CAMPBELL: I could add to this matter, Mr. Chairman.

I received correspondence signed on Mr. Heintzman's behalf dated May 5th which indicated that the matter of further LMSTM runs was a matter of discussion at the recent scoping meeting, and as we, this is I guess signed on behalf of Mr. Heintzman:

> As we submitted at that time we are anxious to get the additional runs in order to make our preparations for cross-examination of Hydro's Panel 10 witnesses. Please advise at once as to the status.

And it suggested that we might want to organize a meeting within the next few days.

By that time we had received a copy of Mr. Poch's letter. And I should point out that the understanding, or I agree with Mr. Heintzman's correspondence that there was discussion of this matter at Panel 10. What I pointed out to him in a reply fax to their offices just after five on Friday, May 8th, was that our understanding of the hearing Panel's disposition this matter at the Panel 10 scoping section was that Ontario Hydro would not be required to perform

additional LMSTM analyses prior to Panel 10, but the parties should recommence discussions aimed at achieving a coordinated approach to this letter.

We note Mr. Poch's suggestion to you, that is to Mr. Heintzman, to arrange a meeting for this purpose. I pointed out that it would not be possible for us to arrange such a meeting within the next few days, as suggested in the letter, and went on to say that it might be helpful, however, if the intervenors could meet initially to determine if a consensus could be reached on a small number of cases, and pointed out that we would have no objection to AECL proceeding on that basis, that is for them to organize such a meeting.

Now, in my submission, and I went back and reviewed the transcript before responding to that correspondence from counsel for AECL, and my submission is that the transcript is quite clear that there was no requirement placed on Ontario Hydro to do LMSTM runs prior to Panel 10 commencement.

THE CHAIRMAN: Do you have the day of the transcript reference? Do you have a transcript reference?

MR. B. CAMPBELL: I think it would have been April 21st. I think that was the day on which all

of this argument...

THE CHAIRMAN: My recollection, and I hesitate to do this without a transcript to be sure, but my recollection is that this did come up, that the feeling was that it couldn't possibly be done within the time frame of Panel 10. There was some discussion suggested and that if there was a Panel 10 problem arising out of whatever the end product was, then we might have to either deal with that by interrogatories or undertakings, or in the extreme, I suppose, recalling Panel 10 to give further testimony. Is that...

MR. B. CAMPBELL: I think if you review the transcript, Mr. Chairman, my clear impression coming away from it was that there was not a requirement to do it prior to Panel 10, that some of this information might be helpful to intervenors in the preparation of their own cases, and that it was recognized that, if necessary, if such runs were done, that it might be necessary to bring back an Ontario Hydro witness at some point in the future, and this was obviously looking well into the future, to speak to the particular LMSTM runs. It was not, I think, contemplated to return the whole panel.

THE CHAIRMAN: Because it was part of

AECL's position, and perhaps others as well, that some of this information, if available, would be pertinent to Panel 10 evidence.

MR. B. CAMPBELL: I know that was AECL's position, Mr. Chairman. I thought that the matter had been disposed of as I described. As I say, before I wrote the letter in response, I did look at the transcript very carefully.

THE CHAIRMAN: Well, you have an advantage over me in that.

Mr. Hamer, what about AECL not responding to the request to come to a meeting of the other parties, what do you say about that?

MR. HAMER: I am trying to track down Mr. Poch's letter. It may be that it was received at Mr. Heintzman's office and didn't get to me, but certainly we will promote the idea of having discussions.

My understanding in rising this morning was that Mr. Heintzman had suggested that Hydro convene a meeting and that would that suggestion was rejected.

The status is this. The discussions haven't lead to a resolution but we have interrogatories which were filed in response to the Update which were unanswered.

THE CHAIRMAN: If they involve LMSTM runs

they can't answer them. That's their position, they can't answer them in time for Panel 10. That's their position, whether that's right or not, that was where we left it, the last discussion.

MR. HAMER: I didn't understand the Board to have ruled that the interrogatories were improper or anything of that nature.

THE CHAIRMAN: There is nothing we can do about it today, anyway

MR. HAMER: No, I am just simply noting it for the record.

THE CHAIRMAN: So, let's going on getting together and discussing it and see what we can do.

MR. HAMER: Thank you.

THE CHAIRMAN: I think there is a real problem about it on everybody's part. If we have to have resolve it ultimately, we will have to do that. That is we being the Panel.

MR. HAMER: Thank you, Mr. Chairman.

MR. B. CAMPBELL: Mr. Chairman, just to make it a little more convenient for you, the volume of the transcript is 136, April 21st, and I think you will see your discussion of this matter, upon resuming. You adjourned briefly to deal with this, you resumed at 12:15, and the page number is 23878, carrying over to

23881.

THE CHAIRMAN: Thank you.

MR. B. CAMPBELL: That is what we have relied on in preparing for this panel.

THE CHAIRMAN: Thank you.

MR. B. CAMPBELL: I might just note that the request to us was to arrange a meeting within the next few days. That was just impossible under the circumstances of getting this panel ready to proceed.

THE CHAIRMAN: All right.

MR. B. CAMPBELL: We have no objection to AECL organizing such a meeting.

[9:42 a.m.]

THE CHAIRMAN: We are going to stop at twelve noon today, so we will probably take the break around quarter to eleven. Would that be okay.

MR. B. CAMPBELL: That will be fine. I will look for some time around the ten-thirty to eleven area where it's a good breaking point.

THE CHAIRMAN: That's up to you.

AMIR SHALABY,
JOHN KENNETH SNELSON,
JANE BERNICE TENNYSON,
FREDERICK GEORGE LONG,
BRIAN PAUL WILLIAM DALZIEL,
HELEN ANNE HOWES; Resumed.

DIRECT EXAMINATION BY MR. B. CAMPBELL (Cont'd):

Q. Now, Mr. Dalziel, if I could pick up with you, please. There have been various factors discussed yesterday dealing with matters which led to the Update. And I guess the first question I have for you is how did these kind of factors that have been talked about, increased demand management, the various changes of circumstance, impact on the plan.

MR. DALZIEL: A. I would like to explain that by looking at or comparing the major supply requirements as we saw them in 1989 and as we saw them heading into the preparation of the Update.

If I could refer you then to page 21 of the overhead package, Exhibit 682, here we are looking at the required major supply by load forecast. There is the firm load forecast for the lower, median and upper. We have also shown the projected load meeting capability as we would define it in 1989. Now that includes the existing system. It includes the purchase NUGs, as we saw them in '89, the hydraulic option, and the Manitoba Purchase is included here so I can make a consistent comparison with the update case.

What we see starting with a comparison of the upper firm load forecast to the projected load meeting capability that from about the mid-1990s and

onwards, there was a requirement for major supply and it continued to increase over the plan period. So, at that time, a question that was facing us was how would we respond with major supply requirements to meet the needs under an upper load forecast case.

When we look at the comparison under the median, we see that roughly from about 1995 out to the year 2001 that the projected load meeting capability is roughly in balance with the median load forecast; and that is what we are trying to achieve in all of our demand/supply planning is that balance between the load meeting capability and the demand. Then after the year 2001, the major supply requirements arise and then they continue to increase over the plan period.

Then looking at the lower, we see that there is a substantial surplus over much of the plan period and it is not until about the year 2008 that there becomes a requirement for major supply.

Now if we look at a similar figure then as we were heading into preparing the Update, which is at page 22, again we are looking then at the major supply requirements as we were considering them before we developed the cases that were described in Exhibit 452.

Again then, we are looking at the update

load forecasts, the firm load forecasts for lower, median and upper, and the projected load meeting capability which again includes the existing system, the purchase NUGs, the hydraulic option and the Manitoba Purchase as we now see them. And to make this comparison consistent, I have not included life extensions here as that was not yet a part of the Update and I am wanting to reflect what we were looking at as we were heading into the preparation of the Update.

This time to compare the projected load meeting capability, I will start off with the lower load forecast line and it has a similar trait in that there is a substantial surplus under lower load forecast over much of the plan period and it is about 2012 that there becomes a need for new major supply.

Under the median, we also see now that there is a surplus again over much of the plan period and this is a substantial change in our view from the 1989 situation where the projected load meeting capability is not in balance with the median load forecast, and it's out until about the year 2009 now that there becomes a requirement for new major supply.

And then when we look at the upper to varying degrees we are somewhat in balance in the early

years and then again around the year 2000. And then it's after the year 2001 that there is a requirement for new major supply.

Now, I have three more figures that I want to use that will help, I guess, reinforce some of these changes or some of the impact of these changes on our thinking as we were preparing the Update. If we turn to page 23 of Exhibit 682, I am looking back again now at the 1989 major supply capacity requirements. And what this figure is doing is it's taking that gap between the projected load meeting capability and the various load forecasts and we are also now taking into account the 24 per cent planning reserve margin. So under the lower, median and upper load forecast conditions, these were the major supply capacity requirements in order to maintain reliability.

Starting with the upper load forecast, the 1989 plan was calling for some CTUs to be installed in 1993/94 in response to the requirements shown. There were some more CTUs being added in 1997. And then the first base load station was coming into service for the year 2002. And then there were additional requirements to match that upper load growth over the remaining plan period, but I will just focus on the first set of requirements.

When we come to the median load forecast, those CTUs that were called for in '93/94 were not used. The CTUs which would have been planned for 1997 would have been utilized in the years 2001, 2002. And the base load station would have been utilized one year later. Then it would have been put in place for the upper load forecast so that in the median load forecast, it was coming in in the year 2003. That was one year after the upper.

And then moving to the lower load forecast, the CTUs which may have been planned for 1997 under upper used in 2001 or 2 under the median, those were the same CTUs which would be used if lower load forecast conditions were to have materialized for the year 2008. And the first base load station was coming into service under those conditions in 2009.

Essentially, what we were looking at from a planning perspective then was that options which would have been planned to the upper would be utilized before too long -- would be utilized before too long under the median load forecast condition. And then if commitments were made to the median, those stations would have been used before too long under the lower load forecast condition if it was to have materialized.

One other feature I would like you to

note from this graph is that if we look out around the year 2010 and beyond, and that is the spread between the lower to the upper the spread in the major supply capacity requirements. And that spread is about 10,000 megawatts, and I just ask you to remember that when we make that comparison to the Update situation.

So turning to the Update situation, that's page 24 in Exhibit 682. And again then we are looking at the required major supply capacity on a consistent basis to meet the Update lower, median and upper load forecast. And I just remind you again that life extensions are not included here in order to make the comparison consistent.

Under the upper load forecast, the base load station could be utilized around the year 2001, 2002 just as it was in the 1989 situation. But then as we move across to the median load forecast, that same base load station wouldn't be utilized until 2009. And then out further again in time under lower load forecast.

[9:55 a.m.]

So there is a spread now of about seven to eight years instead of one year between when a base load station could be utilized under the upper load forecast, and when it could be utilized under the

median load forecast.

And this is a substantial change again from the planning picture that we were looking at in 1989.

Essentially, what we are seeing here then is that facilities which may be planned to the upper are much less likely to be used before too long under the median load forecast condition, and then even longer again under lower load forecast conditions.

So, there has been a greater spread along that horizontal access along time in which the various stations would be utilized under the range of the forecast conditions.

Looking back at the back end of the plan period, out around the year 2014 or 15, and then if we look vertically at the spread between the lower and the upper, we see now that that spread is about 20,000 megawatts, and in fact, by the end of the plan period it's now out to 21,000 megawatts. That's about twice what it was at the time of the 1989 Demand/Supply Plan.

That raises for us some planning questions. For example, with that greater uncertainty in terms of timing and the greater uncertainty in terms of quantity, that we were wondering if we shouldn't be looking at base load options which offer more

flexibility than the 4 by 881 megawatt CANDU station.

One other feature of this graph I would like to draw to your attention and that is the rate at which major supply requirements are increasing, and we see that if we were to go back and compare with the 1989 figure, that the slope of that line is steeper which indicates that on a year-by-year basis the need for new major supply is increasing at a faster rate under the Update than it was in 1989.

I would like to turn to one more figure to reinforce some of the changes, and I will take a moment to explain this next figure which is page 25 of Exhibit 682.

This is the probability that the projected load-meeting capability would exceed load. And to be correct here I would take off the "1989 DSP" in the title, because we are showing the Update and the 1989 DSP.

We display this information in an interrogatory response, 10.33.10, and we were also having to correct that response. We showed the upper line in that response and we will be correcting that response with this figure.

To understand this graph --

THE CHAIRMAN: I am not sure I quite

follow what you are saying about that. I lost you when you started to say take 1989 DSP off the title.

MR. DALZIEL: Sorry. The title says 1989 DSP probability that the projected load-meeting capability exceeds load, we are showing the 1989 DSP and the Update with these two lines. So the graph is not specific to the 1989 situation, it's showing both.

THE CHAIRMAN: Yes. But then you said something about taking one of the lines out.

MR. DALZIEL: I'm sorry. We responded to Interrogatory 10.33.10 and in that response we showed a similar figure with just the Update line on it. And I am just bringing to people's attention then that we will be re-issuing a response to that interrogatory using this figure.

THE CHAIRMAN: Using both lines?

MR. DALZIEL: Yes, using both lines. And that the Update line has been corrected.

MR. B. CAMPBELL: I think we should get a number for the interrogatory reference.

THE REGISTRAR: 683.1.

---EXHIBIT NO. 683.1: Interrogatory No. 10.33.10.

MR. DALZIEL: To help understand this figure it would be useful I think to turn back to page 22. What we see in these figures then is the projected

load-meeting capability crossing the bandwidth of the load forecast. So you could look at a particular year, and let's just take the year 2000, and we see that in the year 2000 the projected load-meeting capability is close to the upper load forecast. And we know that the upper load forecast by definition represents the 90th percentile of the load forecast bandwidth.

So in that year we are seeing that around the year 2000, that not quite but close to, it might be about 85 per cent probability that the projected load-meeting capability in that year would exceed the demand that's forecast for that year.

We could do that for every single year across the plan period and that is what we have done to create the figure that's shown on page 25.

So if we could turn back to page 25.

What this is showing us then is that for the Update, certainly out to the year 2005, and a little bit beyond, that a substantial portion of the upper load forecast has been covered. And this is a big difference compared to the 1989 situation.

It's also showing us that there is a substantial surplus under the median load forecast condition is possible, and that again is a big difference which we can see in comparing the two lines

between the Update and the 1989 DSP.

DR. CONNELL: This still excludes the life extension, does it?

MR. DALZIEL: Yes, it does.

MR. B. CAMPBELL: Q. To put it, Mr. Dalziel, in a way that I deal with things, if I want to look at this and say for the Update, what is the probability that we will be able to meet load in a particular year, I can simply go to that year and go up to the Update line and that gives me the probability that, in fact, we will be in a position to fully meet the load in that year. Is that a fair way of saying it?

MR. DALZIEL: A. Well, it's the probability that - you are close, up until the very last point, and I just like to pick you up on that - and that is the probability that we would be able to cover not necessarily just the median load, but some fraction of the load forecast bandwidth.

If we take maybe the year 2005, what this is indicating is that in the 1989 situation or the time of the 1989 Demand/Supply Plan, that in the year 2005, the probability of meeting the median load, that we were --

Q. Just a minute.

A. Sorry. The probability of the load, the actual demand in the year 2005 being up to the level of the load-meeting capability is .5. And essentially what that's indicating is that the load-meeting capability is roughly in balance with a median level of demand. And then moving up to the Update line, this is now indicating that the probability of the load-meeting capability in the year 2005, that there is about a 70 per cent chance that that load-meeting capability will satisfy the demand in the year 2005.

Q. Okay. So in effect what you are saying in that year, you fully expect that the existing system, its load-meeting capability, could cover up to the 75th percentile of the bandwidth?

A. That's correct. And you could interpret this graph year-by-year on the same basis.

Q. I would ask you ask you then against all of that background to just summarize briefly the planning consequences that you have drawn from all of this?

A. There are three points that I would use to summarize.

The first is that a substantial portion of the bandwidth is covered by this projected

load-meeting capability, and that the need date for new major supply has moved out to about the year 2009 or 10, and one of the results of this then is that there is no need to make a decision on new major supply at this time.

The second point is that under the upper load forecast we could use all of the priority and contract options that are included in that projected load-meeting capability, and the result of this is that Hydro wants to retain these options for flexibility.

The third point is that there is still a requirement in the long run for new major supply, and the result of this, that Hydro wants to keep open its options for new major supply.

Q. Now, the impact and changes to the DSP that you have described, as everyone will be aware at this time, is largely due to the load forecast, demand management, non-utility generation, hydraulic changes. You have also said that environmental considerations and related changing social values influence the Update; is that correct?

A. Yes. Ms. Howes explained yesterday the possibility of tighter environmental regulations and Dr. Tennyson spoke of some of the feedback that we received in our feedback program on the Demand/Supply

Plan.

So, with these changes taken together, there were a number of planning questions that were facing us at the time of preparing the Update and we chose to examine a number of these questions to help us prepare the update cases.

Q. All right. Now, I would ask you to outline briefly, please, what the major planning questions were that you looked at as you moved towards the preparation of the Update.

A. We had six questions that we put together, and very quickly those were, the first one is that we revisited the question of a distributed generation approach, where we would make no additional improvements to the high voltage transmission system.

The second question was, what if we were to incorporate a higher level of environmental controls to reduce emissions and waste on the existing system and to consider other major supply options that may offer lower environmental impacts.

A third question concerned life extensions, and that essentially was, are there some benefits in considering life extensions.

A fourth planning question was, could we be considering CANDU options that would offer more

flexibility than the 4 by 881 megawatt station.

A related and fifth planning question was, could we assume or could we consider an IGCC facility as a base load option.

And those fourth and fifth planning questions are again in response to the desire to have more flexibility in the base load options.

The sixth planning question is, we have just seen, that there is a potential for a surplus under median load forecast conditions, so we were wondering if there was some ways or some benefits if the surplus were to be managed over that period.

Q. And I take it you considered those planning questions, sort of in the course of formulating the update cases or as a preparation for preparing those cases?

A. Yes, we did. We considered these to the extent that we wanted to draw out certain findings. We didn't go through these planning questions and evaluate them in their fullest extent.

Q. All right. I would like you to take us through these one at a time. The first question that you spoke of was revisiting an approach of distributing generation in smaller amounts without therefore requiring any substantial additions to the

bulk transmission system. What did you find what you looked at that set of circumstances?

[10:10 a.m.]

A. Here we considered distributing CTUs and combined cycle plants to meet peak and base load requirements when they arise, and again no major improvement to the bulk transmission system would be made. So, for example, there would be no transmission to incorporate Manitoba Purchase.

And essentially what we find then is that the generation needs to be sited close to the major load centres across the province, and that in turn the major load centres need to become more self-reliant on generation that is within its own area.

We find that we lose the benefits of a high voltage transmission system and as a consequence to this that we would need more generation to maintain a comparable level of reliability compared to the case of centralized stations interconnected by a strong transmission system.

By the end of the plan period, we saw a high reliance on natural gas; about 80 terawatthours a year would be supplied by the CTUs and combined-cycle plants running on natural gas. And just to put that into perspective, that's more than 50 per cent of the

current annual demand for gas in the province today.

Q. That is the total demand in the province?

A. Yes.

This approach would also be more costly. The costs were higher by about $3 billion in present value terms. But a significant factor to us was that certainly because the generating stations need to be distributed close to the load centres, a large number of sites across the province would be required, about as many as 50 sites, and about half of these would have to be required, would have to be sited in the Greater Metropolitan Toronto area.

This approach was evaluated earlier in our demand/supply option studies. And as before, we found this approach to be unsuitable, largely because it forgoes the benefits of a strong transmission system, those benefits that Dr. Macedo described during Panel 7, and also because of the large number of individual sites that would be used.

Q. I take it that the transmission is important in all of this because one of the hoped for advantages in distributing the generation is precisely that: to avoid large transmission networks?

A. That's right.

Q. Now did you carry forward any features of that approach however into the Update?

A. We think we have carried forward a component of this approach in that the non-utility generation program involves generators that to some extent will be distributed across the province. So, to that extent we have carried forward an element of this approach.

Q. Now, I would like to turn you now to your second planning question and that was to determine the effects if additional environmental controls were applied to the existing system and new technologies with potentially lower impacts were used. What sort of controls did you consider in looking at that question?

A. Here we assumed that on the existing system at Lambton, Nanticoke, Atikokan and Thunder Bay would receive a full range of acid gas control measures as well as closed loop service water systems for zero discharge. These facilities would also use low sulphur coal because using lower sulphur coal reduces the scrubber wastes.

Part of Lakeview and all of the Lennox station were assumed to be converted to natural gas and these stations would also be outfitted with NOx controls.

There are also other improvements assumed to the existing nuclear facilities to help reduce emissions and waste management practices.

Q. What new supply options did you review in considering this approach?

A. This approach we considered using in place of CTUs. We would use CTUs operating as combined cycle plant because of their greater efficiency. It also used IGCC plant for base load facilities, but in addition to that it also assumed fuel cells would be available at the latter part of the plan period and it also considered a small quantity of biomass generation using wood from a plantation and wood waste as the fuel source.

There were also about 150 megawatts by improving a few of the existing hydraulic sites. These improvements are currently considered to be uneconomic but for the purpose and the spirit of this case of reducing emissions, it was assumed that those would have been done.

Q. And what did you find when you looked at this approach?

A. What we found is that the use of the fossil system is dramatically over the period 2000 to 2010, but it climbs steadily after that date and

reaches about 60 terawatthours per year. And just for some perspective, that is about twice the typical use of the existing fossil system today. Acid gas emission limits could be respected throughout the plan period with this approach but because the fossil system was not utilized very heavily over that 2000/2010 period, we certainly saw a significant decrease in acid gas emissions over that time period.

Again CO(2) emissions were low up to about the year 2010; and then as the fossil energy requirements increased beyond that date, then the CO(2) emissions increased with it. We also found that costs were higher. So overall we saw that certainly emissions can be reduced as well as certain effluents and wastes with the exception of CO(2). We recognized it was utilizing more diverse supply options but that all of this came with significantly higher expenditures.

Q. Having generally looked at that question, did you carry forward any features of this approach in the preparation of the Update?

A. Yes, we did. All of the update cases incorporate a higher level of environmental controls on the existing system.

Q. Now, your third planning question had

to do with the extension of existing fossil stations. We have heard from Panel 8 evidence on the reasons why life extension was considered and incorporated into the Update. And I guess I would just ask you to briefly address what you found when you evaluated life extension as part of a plan.

A. To consider this question, we assumed that all of the fossil stations on the existing system would be life extended. So, naturally we found that by the end of the plan period there was a substantial reduction in the requirements for new major supply capacity by about 9,000 megawatts. We also saw that the need date for the first new base load station would be pushed back in time by about two years.

The air emissions from this case were -- again the acid gas emission limits could be respected and generally they remained fairly stable over the whole plan period. We saw that costs were lower by about a billion dollars in present value terms, and this gave us, we recognized that this was a margin that might be needed in case life extension costs turned out to be higher than forecast and also if additional environmental controls would need to be added to the stations which were being life extended.

So overall we recognized that this

approach is consistent with the demand/supply planning strategy certainly in terms of maximizing the use of the existing system. The emission limits can be met with this approach. Costs were lower with the margin and also that it reduced the rate at which new major supply requirements were needed.

If you recall earlier in one of the figures I showed, I brought to your attention how the rate of major new supply requirements under the Update conditions were higher than they were in the '89 case, and certainly life extensions go towards reducing that rate.

Q. And again, could you outline briefly what extent you carried forward features of those investigations into the preparation of the cases looked at in the Update.

A. We considered the life extension then of the Lambton and Nanticoke stations for the update cases, recognizing that Lennox is one of our newer stations and less utilized stations, that it too is a good candidate for life extension. So, it has been included in the update cases.

Q. Now your fourth planning question was in relation to utilizing a more flexible CANDU option than the 4 by 881 megawatt station and perhaps you can

again briefly summarize what you found in that area.

A. Well, having reviewed the nuclear options as had been described in Panel 9, we considered the CANDU 6 or we used the CANDU 6 as a representative CANDU option for its improved flexibility in terms of shorter lead time compared to the 4 by 881 megawatt station and also that it can be committed in smaller chunks.

Essentially when we looked then at using the CANDU 6, we didn't really see any major changes or there were no major surprises. The acid gas emission and the air emission characteristics were very similar. Like other plans that used nuclear, we saw that CO(2) emissions remained stable or that they can respect a potential limit in the future.

We found, though, that costs were higher by about $300 million in present value terms but again this I think reflects the difference in the LUECs or was to be expected in that we know the levelized unit energy cost of the CANDU 6 is higher compared to the 4 by 881. So, overall, this approach is similar and there were no unexpected results.

Q. And did you carry forward any features of that approach again into the Update?

A. Yes, we have in that we have assumed

the CANDU 6 or at least the characteristics of the CANDU 6 in the update cases that rely on nuclear as a base load option in the future. We also recognized though that we don't need to make a decision on the major supply option at this time.

Q. Now your fifth question then was to look at the question of what happened if you used CTUs or IGCC stations for new supply requirements. What did you find when you explored that question?

A. We certainly recognized that the IGCC has a shorter lead time; in fact, it even has a shorter lead time than the CANDU 6 station and it can be committed or brought in in roughly the same capacity chunks as a CANDU 6.

We found that energy from coal resources, when you rely on the IGCC for the base load option, increases to about 80 terawatthours a year to the end of the plan period and for some perspective this is about 2-1/2 to 3 times the current reliance on coal today.

Nevertheless, acid gas emission limits can be respected over the plan period. But we do find that the CO(2) emissions, like any plan that would rely on fossil options, that CO(2) emissions continue to increase and would be unlikely to respect a possible

limit that could be set in the future.

Cost were higher in this case by about $600 million in present value terms and again that's a reflection in that the IGCC has a higher LUEC than the CANDU option.

[10:25 a.m.]

Overall we recognized that this approach utilizes an option that has a shorter lead time and some improved flexibility characteristics compared to the CANDU 4 by 881. Acid gas emission limits can be met, however CO(2) emissions tend to increase, and that costs were higher.

Q. All right. And having considered that question, did you carry forward any features of that approach as you prepared the Update?

A. Yes, we did. In the Update we have included cases that use the IGCC station for the base load supply facility, but again we recognize that we do not need to make a decision on that supply option at this time.

Q. All right. And finally, your sixth and last planning question was whether there were particular advantages to reducing the surplus. What kinds of things were you looking at there?

A. Here we considered varying or at

least deferring to varying degrees all of the demand/supply options which were in place over the period of the projected surplus. The deferred options were generally restored then to their target amounts by the time the new major supply would be required.

This was just an illustrative approach to managing the surplus. Essentially what we found was that costs were lower. We also considered electricity prices under these conditions and found that they were reduced by about 5 per cent over the surplus period as a result of this illustrative approach to managing the surplus. So this certainly offered the advantage then of lower prices and lower costs.

Q. And again, having looked at that question, did you bring forward any features of that approach into the Update?

A. Yes, we have. In the Update there are cases that consider illustrative ways of managing the surplus.

Q. Now, having look generally across the horizon at these different questions or issues that you needed to address, what did you do then?

A. We essentially used these planning questions and the lessons that we learned from them to provide some guidance in preparing the set of update

cases, and we focus then on the key features from these planning questions, and in particular the beneficial ones.

Then we moved on to prepare the update cases drawing on these beneficial features such as that lower emissions are possible with a higher level of controls in the existing system, that there can be lower costs or certainly that major supply requirements can be reduced with the life extensions of some of the existing fossil stations, increased flexibility can be provided with the CANDU 6 or IGCC base load options, and that there are some cost advantages for managing the surplus. So these kinds of features were built into the update cases.

Q. All right. I would like to turn then to the update cases an first ask you how many cases you then developed in preparing the Update?

A. We prepared six cases for the Update. Three of those cases generally are as follows: There is the update nuclear case where nuclear is used for base load and CTUs are used for peaking. This case includes life extensions, environmental controls. There is a second update case where it's similar to the first one except we are using IGCC for the base load station and there is no new nuclear in that case. And

a third one is an update, we have called it an enhanced case, where there is a higher level of environmental controls, IGCC plant for base load, combined-cycle plant for peak and other loads, and the use of some alternative energy technologies as well.

Q. And I can take it then in these cases that the update nuclear and the update fossil, they had improved environmental controls generally from where you had been, but the enhanced is a further improvement?

A. That is right.

Q. All right. And did you incorporate the management of surplus into these cases as well?

A. Yes, we did. And that's how we get to six cases. There are the three cases that I just described, and then we have the same three but with the surplus management assumptions built into them.

The ones with surplus management, we referred to them, or at least I will be referring to them later on as update nuclear, update fossil, and enhanced.

Q. All right. I take it that these cases are contained in the DSP Update 1992, which is Exhibit 452; is that correct?

A. That's right.

Q. Could you describe those cases, please.

If you say no, I will be very surprised.

[Laughter]

A. I will describe these cases.

First, I will describe them by looking at the common elements of the cases, and then we will turn to uncommon elements which is essentially the major supply component.

If we could look at page 26 of Exhibit 682, I will also focus on describing these cases under the median load forecast.

This is very similar to a figure that Mr. Snelson showed yesterday, in fact I believe it was page 11 of the package. This is showing the elements of the update cases that take us from the basic load forecast down to our firm load forecast. And so the common elements of the cases are the electrical efficiency improvements, the fuel switching, the load shifting, the load displacement non-utility generation, and the discount demand service that Mr. Snelson summarized yesterday.

If we turn then to page 27 of Exhibit 682, again looking at some of the common elements of the update cases, we have the existing system and here

we are looking at how we arrive at the projected load-meeting capability for all the cases, so we have the existing system including life extensions, purchase non-utility generation, the hydraulic option and the Manitoba Purchase.

Now, this describes the common elements for the update nuclear and the update fossil case. There are a couple of changes I will bring to your attention for the enhanced case.

For the enhanced case, life extension of Lennox was not included. So as a result, in the later years of this graph the projected load-meeting capability would decline, corresponding to the retirement of Lennox.

There also is an additional 150 megawatts in the hydraulic component of the existing system, and that's due to those improvements to a number of sites on the existing system, those improvements are currently considered to be uneconomic but for the enhanced case it was assumed that they would be done. But essentially this describes the common components of the update cases.

Now, if we turn then to page 28, this figure is focussing our attention then on the new major supply requirements for the update cases. Again, we

get down to the firm load forecast with the common priority options and we have the projected load-meeting capability that is similar to all of the cases assumed in the Update, with the exception that the new major supply requirements would be a little bit higher in the enhanced case because of the assumption that Lennox would be retired.

So we see that the new major supply requirements begin about the year 2010, and increase at a fairly steady rate out to the end of the plan period.

So now I want to describe then what I would call or have called the uncommon components of the update cases, and to do that I will first illustrate that new major supply requirements, it's illustrated on page 29, and essentially it is taking that gap between the firm load forecast and the projected load-meeting capability and taking into account the 24 per cent planning reserve margin, and then it's showing the major supply capacity requirements that would have to be added to ensure an adequate level of reliability.

We see that the requirements begin in about the year 2010, and that they increase up towards of around 8 to 8-1/2 thousand megawatts by the end of the plan period.

Now, the next series of three figures that I am going to show, show how the major supply options are added to match the capacity requirements that are indicated by that line on page 29.

So turning then to page 30 of Exhibit 682, we are looking at the addition of major supply on a year-by-year basis.

If you recall the major supply requirements began in the year 2010, so we have showing there being installed in the year 2009 so that it's available for the winter peak in the year 2009/2010. We have a nuclear station being installed, one unit of a 670 megawatt station. In the following year there is a second nuclear station coming into service, and in that same year a peaking facility is being added, a combustion turbine unit with the flexibility for it to be converted to combined-cycle operation. Then in the third year we have more IGCC peaking plant being added, and the third station, CANDU 6 station.

If you can continue to read that figure in that way all the way to the top, essentially what we see then is the new major supply that is being added to the update nuclear case, is a combination of nuclear units, here they are illustrated as CANDU 6 units, and that's for base load, and for meeting peak load

requirements we are adding CTUs.

Page 31 illustrates the major supply capacity additions for the update fossil case, or the update fossil plan. We interpret this figure the same way as the previous one. In 2009 there is the first unit of an IGCC station coming into service, and the second year we have got the second and third units of that station coming into service, in the third year there is the last station of that IGCC station coming into service, and then as well a peaking plant, CTU with the flexibility to be converted to combined-cycle operation coming into service in that third year, and we can continue to read the graph in the same way.

As we see, this update fossil case is using the combination then of IGCC stations and combustion turbine units for base and peak load.

Page 32 of Exhibit 682 is showing the capacity additions for the enhanced case. Again we can read this figure in a similar way, and as we trace up the column we see that IGCC stations are being used for base load, combined-cycle plant is there for peak load, there is also the 150 megawatts of a biomass facility, and FC on this graph stands for fuel cells, and we see that there are about 1,500 megawatts in total of fuel cells added in this case.

Page 33 summarizes the total amount of generation.

Q. Just a moment. Can you go back to page 32 for a moment?

A. Yes.

Q. In looking at 30 and 31 in comparison to 32, the column of resources is higher. I take it that that's as a result of having to deal with the retirement of Lennox in that case?

A. Yes, it is.

Q. All right. Thank you. Perhaps if you could finish up then with page 33.

A. This is summarizing the total amount of capacity that's added by the end of the plan period for the update nuclear, update fossil and the enhanced plans.

The table is largely self-explanatory. I will just draw your attention to the totals, the total line that's boxed across the middle of the page. We see that the total amount of capacity installed under the update nuclear and fossil is very similar. As Mr. Campbell has just reminded me, in the enhanced case there is more capacity added and the reason for that is that the Lennox station was assumed to be retired, and I have reflected that in the line below that total line

called retirements where we see that the retirements under the update nuclear and fossil cases are the same at about 6,600 megawatts, and in the enhanced case the total retirements are 8,900 megawatts.

So the bottom line in this figure is showing the net total amount of generation between what is added and what has been retired. And again for the update nuclear and fossil case it's very similar.

The enhanced case is a little bit higher in comparison, and the reason for that the difference is the degree to which the 24 per cent planning reserve margin is actually met in the final year of the plan.

MR. B. CAMPBELL: Mr. Chairman, that's a general description of the update cases, and we are going to turn to a discussion in various other areas of features associated with those plans, so this would be a convenient time for of the morning break.

THE CHAIRMAN: All right. We will a break for 15 minutes.

THE REGISTRAR: Please come to order. This hearing this hearing will recess for 15 minutes.

---Recess at 10:42 a.m.

---On resuming at 10:56 a.m.

THE REGISTRAR: Come to order. Please be seated.

MR. B. CAMPBELL: I apologize for the little delay, Mr. Chairman.

THE CHAIRMAN: I think we are unusually prompt today. [Laughter]

MR. B. CAMPBELL: I think generally though that you are allowed these things and we are not, so the dynamics are not exactly equal.

Q. I think Ms. Howes, I now want to turn to you and I want to deal with various members of the panel on different features of the Update plans. One of them has been described generally as a set of improved environmental controls and I am going to ask you to describe those for the plans that have been included in the Update.

MS. HOWES: A. Okay. I will just elaborate on the material that Mr. Dalziel presented for the three surplus managed cases: that's the Update nuclear, the Update fossil, and enhanced. I will be referring to Exhibit 646 and I will be looking at specifically Attachment G, which for your purposes in the second last page.

This particular table describes the control technologies for the existing system which were assumed for the three plans. And if we look down the first column called "Controls", they are the controls

by station location. So in the first category is FGD, flue gas desulphurization, for the stations noted. FGD is for SO(2) control and particulate control. Combustion process modifications for some reduction in NOx emissions. MISA requirements for the stations noted. Generally MISA requirements are upgrades to settling ponds, modifications to yard drains, improvements to sewage lagoons, that kind of thing.

The next category is called Zero Discharge. I think more appropriately we should probably call it Closed Loop Service Water System. Generally to reduce discharges to water. The next category is selected catalytic reduction, SCR. The next is baghouses for improved fine particulate removal and trace element removal. The next are enhanced precipitators, ESP. That's for improved particulate removal. And the final one are upgrades to emission controls and monitoring at nuclear stations.

Now across the rows are the in-service dates for each of these controls as well as the number of units upon which the equipment is being installed. So if we look at, say, the first category, FGD at Lambton, under the updated nuclear, updated fossil column, we will see that in 1995 two units at Lambton will have scrubbers installed. And in 1997, two final

units will have scrubbers installed.

The other point I would like to make is that the controls to the existing system are common to both the updated nuclear and updated fossil plans and they are slightly different for the enhanced plans.

Q. Now what controls are assumed for future supply options again under the update nuclear and update fossil plans?

A. We assumed that any future nuclear station would have state-of-the-art controls incorporated into the design. We assumed for planning purposes that a fossil base load was an IGCC with SCR for improved NOx control. And we assumed that any of the CTUs for peaking purposes would be state-of-the-art with the appropriate controls incorporated into the design.

Q. Could you describe please the environmental control technologies for the existing systems that were assumed in the enhanced plan.

A. The whole intent of the enhanced plan was to illustrate the effect of additional controls to minimize emissions and reduce the production of waste. And what I would like to go through is a comparison of the update enhanced column with the update nuclear and fossil column and I will only be focussing on the

differences.

So for the first category: Lambton and Nanticoke. For SO_2 emissions we assumed that there would be burning of medium sulphur coal, that's 1.4 per cent sulphur coal on all the scrubbed units. And for any unscrubbed units that we would be burning 0.9 per cent sulphur coal. This would reduce SO_2 emissions as well as reduce FGD waste volumes.

If you look under the CPM category for Lambton and Nanticoke, we assumed CPMs for Nanticoke essentially to get emissions or to get NOx emissions sooner. You will see that we have them installed in 1996 and 1997.

If you then focus on the SCR category for Nanticoke, you will see that there is some advancement in the years for the installation of SCR in the enhanced plan over the update fossil and update nuclear plan.

Another difference is in the next category: baghouses. You will note that we assumed baghouses for Lambton and Nanticoke whereas as in the update fossil and update nuclear plan enhanced precipitators were assumed. As well for these two stations, we assumed a closed loop service water system, so under zero discharge you will see that there

was a closed loop system assumed for the enhanced plans over the other two plans.

Q. What were the changes in the enhanced plan as between Lakeview, Lennox, Thunder Bay and Atikokan on the existing system?

A. If we focus at the bottom of the table to the category gas conversion. In the enhanced plan, both Lakeview and Lennox were converted to gas to get improved SO_2, NOx, CO_2 and particulate emissions. Lakeview was converted to gas in the period 1998 to 1999 and Lennox in the period 1996 to 1997.

In addition, if you look under CPMs, CPMs were installed earlier at Lennox to get earlier NOx control. And then if you look down at the SCR category, you will find that SCRs were also installed at Lennox. And at Lakeview instead of installing CPMs we installed SCRs as soon as possible for improved NOx control.

Q. And at Thunder Bay and Atikokan?

A. For Thunder Bay and Atikokan if you could focus on the FGD section, both Thunder Bay and Atikokan scrubbers were installed FGD. That was for improved SO_2 control. And if you look at the SCR category, SCRs were installed at both Atikokan and Thunder Bay. And baghouses were also installed at

Atikokan and Thunder Bay which is different from the update nuclear and update fossil plans.

Q. Were there any additional control technologies or upgrades assumed for the nuclear stations?

A. Yes, there were. In the enhanced plan it was assumed that there would be improved tritium recovery, improved active liquid waste management system, and improved management or handling of low level radioactive waste. It should be noted that most of these upgrades are under way at at least one nuclear station. We assumed that all stations would have all of this, all of these upgrades.

Q. And did the enhanced plan consider any different future supply options?

A. Yes. As Mr. Dalziel has stated, there were some additional hydraulic upgrades assumed. We assumed gas-fired combined cycle with SCR for NOx control. That is for peaking purposes. And for base load, we also considered fuel cells because of their high efficiency and low air emissions. We also considered wood waste and biomass plantations and the major base load was proposed an IGCC with SCR for NOx control.

Q. Now, Mr. Dalziel, I would like to

come back to you then. You have indicated that some of the plans include surplus management assumptions and I would ask you to describe the kinds of approaches that Hydro could take in managing the potential surplus.

MR. DALZIEL: A. First of all, Hydro recognizes that it must manage the surplus if it arises and as it arises.

The options to manage the surplus will be determined by Hydro over time as the decisions need to be made. With time we will have more information on the actual load growth experience and the yields from the demand management and the NUG programs for example. So, we don't want to make these decisions before they have to be made.

We realize that if growth is along the upper load forecast, that we would need all of the options that are in that surplus period. All of them would be utilized to contribute to maintaining reliability.

Exhibit 452 illustrated the kinds of steps we could take in managing the surplus but it is important to emphasize that what we really want to do is review this decision over time, the decisions that need to be made on how to manage the surplus.

Q. Could you identify what kinds of

options are available to you as you make these decisions over time to manage the surplus.

A. Essentially the options for managing the surplus are to defer demand management, defer non-utility generation, defer the hydraulic program and to mothball plants on the existing system.

Exhibit 452 illustrated one approach for the update nuclear and update fossil plants, and that was that some demand management was deferred and then it was recovered by the year 2008. Some NUGs were deferred and then they too were recovered before the time that new major supply was required. Much of the hydraulic capacity was deferred in time; and for the purpose of this illustrative way of managing the surplus, it was assumed further that the Little Jackfish project would be cancelled, but that the rest of the hydraulic programs were recovered by the time major supply was required. There were also some units on the existing system that were mothballed.

The lower nuclear performance from the existing system also has the effect of reducing the surplus and this has been noted in Exhibit 452.

The enhanced case managed the surplus differently. It had a different illustrative approach. The demand management, the non-utility generation and

the hydraulic options were left at their forecast levels or their unmanaged surplus levels. And instead, it took the approach of mothballing fossil stations on the existing system. Specifically half of Lakeview was mothballed over the period '93 to '96, half of Nanticoke was mothballed in '98 and '99. The Nanticoke units returned to service over the period 2003 to 2008 whereas the Lakeview units remained out of service until their retirement date.

I have a figure which shows the effects of the surplus management approaches. This is page 34 of Exhibit 682 and the scale goes from minus 1 gigawatt to a total of 6. The zero line on the graph is just indicating the degree to which the amount of generation is in balance with the demand in that year. If the planning reserve margin in these cases was exactly 24 per cent, then the line plotted would run along that zero line on this graph.

So what we are seeing then is the top line or the upper line on this graph is the surplus capacity without surplus management assumptions and we see that it starts off around 2,000 megawatts and by the year 2,000 it peaks at nearly 5,000 megawatts and then declines over time.

Then, the update nuclear, update fossil

and the enhanced cases for the managed surplus are the other three lines plotted on the graph and we see that in general the surplus, the illustrative ways of managing the surplus are effective in bringing the reserve margin in line with the target.

One other point I would like to make and that is to point out that the surplus management assumptions, they do not effect the major supply requirements or the major supply component of any of the plans. Surplus management is something that is taking place before the time that new major supply requirements are needed.

Q. Now once the existing system, demand management, non-utility generation, Manitoba Purchase, hydraulic and the major supply options are specified, how do you then go about evaluating that set of facilities that you now have in front of you?

A. We evaluate plans by applying the demand/supply planning strategy criteria that Mr. Snelson described yesterday. The early stage of a plan evaluation relies on energy production simulation. And one of the reasons for that is that applying many of the criteria relies on the results of an energy production simulation such as quantifying the amount of fuel use, other environmental impacts, costs and

impacts on rates.

So we model then the new and the existing options and the simulation essentially tracks the demand reducing options as set out in the load forecast and it predicts the operation of the supply options and predicts the operation of the supply options to meet primary demand consistent with the various constraints that there may be on individual options. For example, the hydraulic facilities can be limited in the amount of energy they can produce in a single day or in a month.

It also takes into account system limitations and the example of that is the acid gas emission limit.

Q. I would ask you then to describe the result of the energy predictions for the update cases.

A. I will describe this for the median load forecast and I will focus then on the cases with surplus management. And if we could look at page 35, of Exhibit 682, I'm using the top graph to illustrate the energy production for the update nuclear and fossil case and the lower graph on this page is the energy production for the enhanced case.

Focussing first then on the top graph for the update nuclear and fossil, this is similar to the

figure that was illustrated in Exhibit 452 and further details on the energy production information is contained in Exhibit 646 under attachment C, I believe.

The top line on this graph corresponds to the basic load forecast. But I will start from the bottom and work up and I will also focus the energy production results towards the end of the plan period.

The Manitoba Purchase is contributing about 7 terawatthours a year by the end of the plan period or over much of the latter period. The hydraulic component begins at 36 terawatthours a year and then with the new options it increases to about 39 terawatthours, almost 40 terawatthours, by the end of the plan period.

The existing nuclear facilities, they are shown here starting out at about 80 terawatthours a year. Over most of the plan period they are producing about 95 terawatthours per year. And then with retirements, the existing nuclear facilities decline to about 55 terawatthours a year by the end.

Now, depending on whether the new major supply is provided by the nuclear options or whether it's provided by fossil options, the total amount of nuclear will vary. If there are nuclear options, then new nuclear is providing about 45 terawatthours by the

end of the plan period, so the total amount of nuclear would be close to the 9,500 terawatthour level. In other words, in the update nuclear case, the level of energy being produced from nuclear by the end of the plan period is fairly constant over the entire plan period.

If the new base load supply facilities are fossil, then what we find is about 49 terawatthours a year is being produced by the new fossil options and the update fossil case; and then combining that with the existing fossil energy production, that's about 30 terawatthours a year by the end, so 49 and actually 31 brings us to about 80.

[11:20 a.m.]

So in the update fossil case the total amount of energy being produced from fossil facilities would be about 80 terawatthours per year. And just for some perspective, that's about 2-1/2 to 3 times the current use of fossil on the existing system.

The next contribution shown here is from purchase NUGs and that's about 25 terawatthours per year by the end of the plan period. And then on top of that are the demand reducing options which are saving about 35 terawatthours per year by the end of the plan period.

Looking at the enhanced case, which is the lower graph on this page, 35, the enhanced case, the new supply facility are predominantly fossil, the fuel cells, the IGCC plant.

So going over this again starting from the bottom, the Manitoba Purchase and the hydraulics are -- and the existing nuclear system behave in much the same way as they do in the update fossil/update nuclear case.

Because the new supply is predominantly fossil options, the total amount of fossil energy in this case is again 80 terawatthours a year by the end of the plan period, the purchase NUGs again are 25 terawatthours per year by the end, and the demand-reducing options are saving 35 terawatthours a year by the end.

I would just like to point out in this case, because it had a different approach to managing the surplus, that over the period 2000-2010 in particular, there is a little more energy being contributed by the demand management, purchase NUGs and the hydraulic option, and as well the Manitoba Purchase. In the update nuclear/fossil case it was assumed that over the years 2000-2010, the supplemental energy that's available threw the Manitoba Purchase

contract would not be taken as part of the illustrative approach for managing the surplus. In the enhanced case that is taken.

So over those years, in the enhanced case, 2000-2010, there is a little more energy being contributed by the Manitoba Purchase, the purchase NUGs, the demand-reducing options and the hydraulic option.

Now, some of the environmental impacts that Ms. Howes will be describing as a result of the energy production, and also because fossil is the major variable between the various cases, both in the use of the existing system and in new supply options, we will take a look at the energy production from the fossil resources from coal, oil and natural gas.

Page 36 is an illustration then of the coal energy production for the update plans.

Essentially what we are looking at then, this scale is going from zero to 100 terawatthours, and over the plan period then, at least up to about the year 2010 for the update nuclear and fossil cases the energy from coal is essentially the same, and it's not until then that we get into the period where new major supply is required that there becomes a difference, and that depends on whether the new base load supply

facilities are IGCC or whether they are nuclear.

If nuclear is used, then we see that the level of coal energy is generally the same over the entire plan period, with the typical variability in the use of coal.

If fossil option is the base load supply option then we see that the reliance on coal increases towards 80 terawatthours by the end of the plan period.

We see that in the enhanced case that there is a reduction in the use of coal over the period 2000 to 2010, and again that's because, as I mentioned earlier, the effects of a different way of managing the potential surplus over those years were relying more on the demand management and the purchase NUGs, hydraulic, and Manitoba Purchase.

The enhanced case has lower reliance on coal than the update fossil case in the latter years of the plan period and that's due to the energy that would be coming from the fuel cells which have been assumed in this case.

If we turn to page 37 of Exhibit 682, we will look at the oil and gas use.

Oil is shown in the top figure and natural gas in the bottom figure.

The top figure applies to the update

nuclear and fossil case. Essentially in the enhanced plan there is no use of oil, or certainly very little use of oil. You will recall that the Lennox generating station was assumed to be converted to gas and also in the enhanced case it's assumed that gas would be used in CTUs and not a combination of oil and gas.

So the use of oil in the update nuclear and fossil case up to the year 2010 it's largely reflecting the use of how the Lennox station would be used, and then beyond that period it's a combination of Lennox and the new combustion turbine units that would be added for meeting peak load.

This is shown as oil energy production and that's the way it was simulated, although we recognize that the CTUs may well use a combination of oil and gas, depending on the type of gas contract that you actually end up and whether gas is available at the time that you need it. But here we have assumed that for the purposes of the simulation that oil would be used in the CTUs.

Then looking at the bottom figure, it is showing the natural gas energy production for the enhanced plan. Essentially what we are seeing then is the use of natural gas in the Lennox station up to about the year 2010, and then beyond that, that's the

use of gas in the combined-cycle plant that's add in this case, and the fuel cells. And certainly up to the retirement date of Lennox there may be some gas used in Lennox, but in this case Lennox is assumed to retire.

One more figure to describe for the energy production results and characteristics of the plans is to look at the energy produced by the alternative energy technologies assumed in the enhanced case, that's shown on page 38. We see that there is a small contribution of energy from the 150 megawatts of the biomass facility that's used in the enhanced case, and we see that the fuel cells are providing by the end of the plan period about 9 terawatthours of energy, and that is coming from natural gas fuels.

Just to summarize what we have been looking at then, is that the update nuclear and fossil cases are essentially the same in their energy production patterns out to the year 2009 when new major supply is required, and then the differences between those cases are dominated by whether you assume a nuclear facility for base load or whether you assume a fossil facility.

The enhanced case is showing low fossil use during the period of the surplus, and then after the year 2009 it's showing that fossil energy

production increases from that point, 2009 to the end of the plan period.

That generally describes the energy production characteristics of the cases and further details are available in Exhibit 646 under attachment C.

Q. All right. Ms. Howes, I would like to come back to you then. I want to deal in a fairly efficient manner, if we can, please, with the various emissions that are associated with the update plans, and I would first ask you to deal with SO(2) emissions.

MS. HOWES: A. Okay. I will be first referring to overhead 39 in your overhead package.

Just to make sure that everyone understands, the first bar is the update nuclear, the second bar is the update fossil and the third is the update enhanced. Some of the Xeroxes did not come out clearly.

But it's clear from here that the enhanced plan has the lowest total emissions of SO(2) for all of the cases. The lower SO(2) in the enhanced plan is due to the installation of scrubbers on all stations and the burning of medium sulphur coal.

If we can flip to the next overhead on page 40. This is an index, this is gigagrams per

terawatthour and the terawatthours are the total energy produced over the planning period, and Mr. Dalziel referenced the terawatthours in his previous presentation.

But it's clear from here that if you look at the update nuclear and update fossil, update nuclear is the one with the little square and update fossil is the cross, that SO(2) emissions are common between those plans to about the year 2010, and beyond that period the update fossil plan has higher SO(2) emissions than the nuclear plan. And you will see if you look at the starred line, the enhanced plan, it has lower SO(2) emissions over the entire planning period.

It's also instructive to note that if you look at the trend you will find that over the planning period there are declining SO(2) emissions, and that's because of the installation of the control technologies in this particular plan.

Q. And again that trend is on a per terawatthour basis?

A. Per terawatthour basis, that's correct.

Q. And could you describe, please, looking at your next chart, I would like you first to describe the potential regulation line for SO(2).

A. Right. That's on the next page, page 41.

As you heard me mention, one of our planning assumptions was that environmental regulations would become tighter over the planning period. And currently SO(2) emissions are regulated under regulation 281/87 of the Ontario Environmental Protection Act, and in 1994 this regulation will limit Hydro's SO(2) emissions to 170 gigagrams per year.

Now, although Ontario Hydro and the provincial government have not yet begun discussions regarding emissions post 1994, there is some expectation that the regulatory limit beyond 1994 will be tighter. I think evidence for that is comments in the federal Green Plan as well as recent meetings of the Canadian Council of Ministers of the Environment, and both of those have suggested that additional control measures will be required for SO(2) beyond 1994.

Now, the current emission regulation targets for Canada's Countdown Acid Rain Program, as well as the U.S. Clean Air Act Amendment were based on a 1980s critical load value of 20 kilograms per hectare per year of wet sulphate deposition. Now, at that time it was thought that was adequate protection for sport

fish in sensitive lakes. However, more recent evidence suggests that this critical load for wet sulphate is not adequate to protect all ecosystems and that lower target loads are more appropriate, perhaps as low as 8 kilograms per hectare per year.

So as a proxy for reduced SO(2) limits we assumed that 50 per cent of our 1994 regulatory limit or 90 gigagrams was an appropriate proxy for a potential limit in the future, and that is what is shown on this graph as the dotted line, potential regulation.

Q. How did the plans compare against this potential regulation?

A. As we can see from the graph all of the plans are well below the regulatory limits and the potential regulation limit.

Q. Could you turn then to the topic of NOx emissions and deal with those emissions.

A. We are referring to the overhead on page 42. Essentially the same pattern of emissions, the NOx emissions for the enhanced plan are significantly lower than for the update fossil and the update nuclear plans. It's because in the enhanced plan there were additional NOx control technologies assumed.

Now, if we could turn to page 43, in this particular diagram you will see again that the enhanced plan has the lowest NOx emissions over the period. Those again are due to the use of both CPMs and SCR for NOx control.

You will note as well that NOx emissions for the update nuclear and update fossil plan are similar to the year 2010, and then as you would expect the NOx emissions for the update fossil plan are higher.

I should also point out again the trend, you will see a declining trend in NOx emissions on a per terawatt basis over the planning period.

Q. Now, again, if I look at the next page I see a target line for NOx. Could you explain the derivation of that line, please?

A. The dotted line for the period 2000 to 2005 represents a commitment by Ontario Hydro to limit its NOx emissions to 38 gigagrams as NO, nitric oxide, by the year 2000. This represents a 40 per cent reduction in Hydro's NOx emissions from 1985 levels, and this was the commitment that Hydro made resulting from Phase 1 of the federal/provincial management plan for NOx and VOCs. In addition, Hydro made a commitment to have investigate other ways of controlling NOx

beyond the year 2000.

Now, Phase 2 of the NOx/VOC plan will establish final emission caps for the Windsor to Quebec corridor by the year 2000. Since this cap is not known at this point, what we assumed for the period 2005 to the end of the planning period, which is the lower dotted line, as a 25 gigagram as NO target. This was the interim reduction target that was proposed for Hydro as part of the Phase 1 of the negotiations. And that 25 gigagram line would represent a 60 per cent reduction in Hydro's NOx emissions from 1985 levels.

Q. Now, you have referred to the management plan for NOx and VOCs. Could you tell me what have VOC stand for?

A. Volatile organic compounds.

Q. Again, could you just briefly outline how the three plans compare against this possible target?

A. As you can see from the graph, all of the plans are significantly below the target and that possible target line from 2005 to the end of the period. The update fossil plan approaches the line towards the end of the period, but is still well below.

Q. All right. Now I would then like to turn to you to a discussion of trace emissions and

particulates, and again ask you to compare the plans on that basis.

A. Referring to figure 45. Again, the enhanced plan has lower trace element emissions than both the update nuclear and update fossil plans. It's because of the use of baghouses to reduce fine particulate matter and trace elements.

If we flip to the next one on page 46. This is an index, it's gigagrams per terawatthour basis. You will find that the trace element emissions to the year 2010 are common between the update nuclear or very similar between the update nuclear and update fossil. They are slightly higher for the update fossil beyond the year 2010.

The enhanced plan has lower emissions of all of the plans over the period.

Again, we see a declining trend in trace element emissions on a per terawatt basis over the planning period.

Q. Are there currently any emission limits that are directly related to trace elements?

A. No. There are no emission limits but there are air quality standards for the stations. I know this was described in some detail in Panel 10, but just to refresh your memories --

Q. Panel 10?

A. 8. We are 10. Sorry.

Trace element emissions are currently regulated to meet point of impingement standards, and this is as specified under the Environmental Protection Act.

Air quality modelling is done to determine the point of impingement concentration of given trace elements for a given source, like a coal-fired station. Licensing of emission sources is then done to ensure that the emissions stay within the air quality criteria.

Now, I do recall too that the Clean Air Program was described in Panel 8, and things like the modelling methods, the number of pollutants to be controlled as well as the extent of control are still under discussion currently and we will likely see them as part of an air management strategy for the Province of Ontario.

[11:40 a.m.]

Q. And in these plans, how did you attempt to account for more stringent future regulatory action with respect to trace elements?

A. Research suggests that if we control particulates, we will also be minimizing the release of

most trace elements in the flue gas. So we assumed in the update nuclear and update fossil plans, enhanced precipitators; and for the enhanced plan we looked at baghouses. We also felt that installation of scrubbers at our fossil stations would also result in some improved level of trace element removal.

Q. And then again could you just briefly outline how the plans compare on a particulate emissions basis.

A. We will be referring to figure 47. Again, a similar picture to what you saw for trace elements. Beyond the year 2010, the update nuclear plan has lower trace elements than all of the three -- sorry, lower particulate emissions than the other two plans. This is because the major supply option for the update nuclear plan is a non-fossil alternative. And we see again generally the same trend: declining particulate emissions on a per terawatt basis over the planning period.

Now, Ms. Howes, I would like to turn you then to some discussion of the issues around greenhouse gases and I guess first if you could just recap for the Board, summarize the various greenhouse gases that do result from Ontario Hydro's operations.

A. Yes, there are generally five

greenhouse gases that result from Hydro's operations. The first is chlorofluorocarbons, knowns as CFCs. These are primarily from the dry cleaning of protective clothing and decontamination of equipment at our nuclear generating stations.

Second is methane. This is primarily from flooding for reservoirs at our hydraulic stations.

Third is ozone. Now ozone is not emitted from our fossil stations but nitric oxide, NO, is emitted and it's a precursor to ozone. And in an attempt to limit ozone formation, Ontario Hydro is managing its NO emissions.

The next is nitrous oxides N(2)O. These are released from our fossil fuel combustion at our fossil stations.

And finally carbon dioxide which is primarily released from fossil fuel combustion at our fossil stations.

Q. And are their legislative requirements to control greenhouse gases?

A. Generally, yes. The Montreal protocol and its amendments provided the legislative requirement for the government regulation of the phase-out of CFCs. Now, Canada was a signatory to this particular protocol and committed to a 50 per cent

reduction of these controlled CFCs by 1995 and 100 per cent reduction in CFCs by the year 2000.

And Hydro has a program in place to eliminate the use of controlled CFCs by the year 1995. And the major component of our program is to replace the dry cleaning facilities at Bruce and Darlington with wet wash facilities.

With respect to methane, there is no legislative control for methane.

As I have mentioned before, for NOx the federal NOx/VOC management plan provides the legislative framework. 95 per cent to 99 per cent of the NOx produced at our fossil stations is NO. Ontario Hydro is committed to a 38 gigagram target by the year 2000 and as I mentioned before is committed to reducing NOx further beyond the year 2000.

There is no specific legislative requirement for the control of nitrous oxide, N(2)O, but it is controlled under Regulation 281/87.

Now the target of stabilization of CO(2) at 1990 levels by the year 2000 was endorsed by the Canadian Council of Ministers of the Environment in March 1992. Although there was no action plans signed, there was an agreement to work with the energy ministers to develop such strategies. It is

interesting to note that at that particular meeting the Minister of the Environment for Ontario acknowledged that Ontario Hydro's energy conservation program was one of the major steps that the province is taking to reduce CO(2) levels.

Q. And what other steps are being taken by Hydro in this regard?

A. I think there are several other steps. One is, as I mentioned, the demand management programs. Second, more non-utility generation options in the Update will mean increased use of renewable resources such as small hydraulic and the use of high efficiency gas-fired non-utility generation options will result in less CO(2) per terawatthour than, say, conventional coal options.

There is also priority in hydraulic generation with low CO(2) emissions. We are improving the efficiency of our existing system through life extension and this will likely result in some reduction of CO(2) per terawatthour.

Our current nuclear program with the addition of the Darlington units will help to reduce CO(2) emissions across the system. We are also investigating fossil options with lower CO(2) per terawatthour levels such as IGCC and combined cycle.

We are also investigating alternative technologies which generally have lower CO(2) emissions per terawatthour and those are such things as fuel cells, biomass plantations, wind, photovoltaics and wood waste. And in addition, we have a program under way to replace trees removed through a right-of-way clearing and through hydraulic developments.

Q. And how do the plans compare on the basis of annual CO(2) emissions?

A. I will be referring to figure 48. Generally the update nuclear plan has lower CO(2) emissions than the other two plans. And as you would expect the update fossil plan has the highest emissions.

If I can turn to the next figure, figure 49. You will see in the early years to about 2010, the enhanced plan outperforms the other two plans in terms of CO(2) emissions, and this is because this particular plan mothballed fossil plant as part of the surplus management illustration and there was also conversion of two fossil stations to gas.

In the period to the year 2010, the CO(2) emissions are similar between the update nuclear and the update fossil plan. Beyond that period, the CO(2) emissions for the update nuclear plan are certainly

considerably lower than the CO_2 emissions for both the enhanced and the update fossil plan.

Now the trend in CO_2 emissions as you see again this is an index, this is on a per terawatthour basis. Generally you can say that the update nuclear plan has stable CO_2 emissions over the planning period. For the fossil plan it's relatively stable to the year 2009 and then increases quite dramatically.

For the enhanced plan there is somewhat of a decline to the year 2009 and then there is a significant increase in CO_2 emissions.

Q. How do the CO_2 emission levels compare to the possible limit which would represent a stabilization of emissions at 1990 levels?

A. That's figure 50 or page 50, I guess. The dotted line is a 25 teragram limit and that is a stabilization at 1990 levels. All of the plans are below that limit to about the year 2010.

Beyond that period, both the fossil, update fossil, and the enhanced plan are higher than this possible limit line. You will find, too, that the update nuclear plan is slightly higher than that dotted line for several years in the period about 2011 to 2012.

Q. Now, looking at that period beyond about 2010, to what degree to you see this CO(2) production at levels higher than the illustrative targets shown on page 50 as being a concern?

A. It certainly is a concern but based on this median load forecast we have a number of years to work out some answers and our problem lies in the period beyond the year 2010. Greenhouse gases are just one of the air emissions that Ontario Hydro must manage as part of the operation of its bulk electrical system. And we neither plan or operate our system based on the management of just one air emission. And really we must consider the management of all of the air emissions SO(2), Nox, CO(2), radionuclides, particulates and trace elements as well as the synergistic effects of the controls.

For example, if you install scrubbers on a station you are reducing the efficiency of the stations as well as producing a waste. In reducing the efficiency of the station, you are resulting in higher CO(2) emission. I guess what I'm trying to say is that it really isn't a black and white issue, that environmental trade-offs will have to be made.

Q. Now, you scrub for SO(2) and I guess the question to you is whether Hydro is investigating

CO(2) control technology, CO(2) scrubbers?

A. We are not actively investigating CO(2) scrubbers but we are monitoring some pilot CO(2) scrubbers that are currently being tested in Japan and West Germany. And although the technical aspects of decarbonization appear quite simple, the early test results are not very promising. For example, the energy costs associated with the removal of CO(2) are very high. For example, there is a drop of one-third of the power plant energy for a 50 per cent removal of CO(2) and there is a four-fifths drop in the power plant energy for a 90 per cent removal.

What this results in is essentially a doubling of the cost of fossil-derived electricity if you are using CO(2) scrubbers. There is also a significant waste management issue. You need some way to use the scrubbed CO(2) or some place to dispose of the solid waste. At this point capital costs are really not known and this technology has not been tested on North American coals.

Q. I want to turn then to the general area of the MISA program and toxic discharges to water. And I guess the simple first question is how the plans compare on the basis of meeting MISA requirements.

A. As I have mentioned, certain controls

to meet MISA requirements were assumed for each of the stations. You should be aware that Ontario Hydro is currently negotiating Phase 2 of the MISA program with the provincial government. Phase 1 of the programs was the monitoring phase, and now with the monitoring results available, the discussions now focus on what control technologies will be assumed at our stations.

For planning purposes, we assumed that the MISA regulation for Ontario Hydro would come in at about 1996. Whatever controls are regulated will be common to all of the plans.

Q. And does the enhanced plan assume additional water emission controls?

A. Yes, as Mr. Dalziel had mentioned, we assumed a closed loop service water system for the enhanced plan which is somewhat different than the other two plans.

Q. And can you compare then water use across the three plans.

A. I will be focussing on figure 51. And generally water use across the plans is very similar.

Q. Were there any differences in cooling water use or discharges of thermal effluents among the three plants?

A. Focussing on 53, figure 53, there is a slight difference in cooling water use among the plans. The update nuclear plan has slightly higher cooling water use and slightly higher thermal discharge than the other two plans. It is because a nuclear supply option would require greater cooling water than a fossil option.

If we just focus on the next page, it's figure 54, and it's thermal discharge. And you will see again the update nuclear plan has a higher thermal discharge than the other two plans.

Q. Now, Ms. Howes, I just want you to confirm. We have got in the package figures 55 and 56 which deal with solid waste; 57 and 58 which deal with fossil wastes and ash and flue gas desulphurization wastes; 59 and 60 which deal with radioactive waste comparisons; and 61 through 64 that deal with radioactive emissions. And I take it that the comparisons in all of those areas are fairly straightforward and well illustrated by the overheads. Would that be fair?

A. Yes. But if I could take a moment's indulgence just to focus on figure 56. This is total waste during the generation phase and again it's on a per terawatthour basis. The only point I wanted to

make is unlike the other trends we are showing a slight increase in waste production on a per terawatthour basis over the planning period.

And if we flip to figure 58, this is the major reason why, because we are using scrubbers to control SO(2) and SCR to control NUGs, what is resulting is a greater waste problem than we had prior to this. So, we are getting a decrease in emissions on a terawatthour basis but an increase in waste on a per terawatthour basis.

Q. Now, Ms. Howes, I then want to turn to the topic of resource use and ask you to do a brief comparison of the plans with respect to the use of fuel resources.

A. I will be using figure 65. Coal consumption is lowest in the update nuclear plan. If you look at this particular diagram to the year 2010 coal consumption is similar between the update nuclear and the update fossil plan.

Coal consumption is lowest for the enhanced plan due to gas conversions for the fossil stations and a managed surplus situation which was mothballing the Nanticoke units. Beyond the year 2010, the update fossil plan consumes more coal than the enhanced plan. If you recall, the enhanced plan over

this later period 2010 and beyond relies on alternative energy options rather than coal technologies. And generally over the planning period again on a per terawatthour basis you see that there is a significant increase in coal consumption.

Now, if we flip to the next page which is 66 and it focusses on uranium. Again an indulgence. At the top left corner it says megagrams per terawatthour. It should read gigagrams per terawatthour, big G, little G.

Uranium consumption is generally the same for all of the plans to about the year 2010. And then as you would expect, it increases for the update nuclear plan. Generally on a per terawatthour basis, the consumption of uranium decreases over the planning period and you would expect that the enhanced plan and the update fossil plan have lower uranium consumption in the period beyond 2010.

The next one, page 67, focusses on natural gas. As Mr. Dalziel has mentioned, gas use is the highest for the enhanced plan and it's is quite apparent on this particular table and that's because of the gas conversions of the fossil stations and the use of gas-fired future options. This is fuel cells for major supply as well as combined cycle for peaking

purposes. You will see if you look across the X axis that there is little to no gas use in the other two plans.

If we move on to the next figure, figure 68, this one focuses on oil consumption.

[11:54 a.m.]

Oil consumption from this chart is the highest for the update nuclear plan, it's because of the higher use of oil-fired CTUs for peaking purposes, and again there is, as Mr. Dalziel has noted, there is very little oil consumed in the enhanced plan.

Q. I am going to ask you to round this out as we come up to noon, to deal with the comparisons with respect to land use.

A. I will be referring to figure 69.

It's apparent from this chart that the highest land use is for the enhanced plan. This is primarily due to the requirement for a biomass plantation, there is a large requirement for a growth of trees.

The update fossil plan has the next highest land use and it's due to the land required for coal mining and waste disposal. The lowest land use is for the update nuclear plan.

MR. B. CAMPBELL: It being twelve

o'clock, Mr. Chairman, this would be a convenient time to for the break.

THE CHAIRMAN: We will adjourn until two o'clock.

THE REGISTRAR: Please come to order. This hearing will adjourn until two o'clock.

---Luncheon recess at 12:00 p.m.

---On resuming at 2:03 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Be seated, please.

THE CHAIRMAN: Mr. Campbell?

MR. B. CAMPBELL: Thank you, Mr. Chairman.

Q. Ms. Howes, I just want to wrap off the review of some of the environmental characteristics associated with the update fossil, nuclear and enhanced plans by having you briefly summarize, please, what you see as the environmental advantages and disadvantages of these three cases.

MS. HOWES: A. I will be referring to figure 70. You will see on this particular figure there are three columns, the first is the enhanced plan, the second the update nuclear and update fossil. Generally I will focus just on the highest and lowest, the advantages and disadvantages of each of these

plans.

If you look first at the update nuclear plan you will see that it has the lowest coal use and gas use among the plans, it has the lowest land use, it has the lowest CO_2 and particulate emissions of the three plans.

On the other hand, it does have the highest uranium and oil consumption, the highest cooling water use, the highest radionuclide emissions, highest thermal discharge, and it has the highest waste volume but it's the same waste volume as the update fossil plan.

Next if we focussed on the update fossil plan, you will see that the update fossil plan has the highest coal use, generally the highest air emissions of the three plans, and the waste volume is high but it's of approximately the same volume as the update nuclear plan.

If we look again at the first column, the enhanced plan. The enhanced plan has the lowest oil and uranium use, it has the lowest cooling water use, the lowest SO_2 and NO_x emissions, and trace element emissions, it has the lowest thermal discharge, and the lowest waste production. On the other hand, it does have the highest gas use and the highest land use of

the three plans.

I would also like to remind you that when we were going through the trend of graphs, generally the emissions on a per terawatthour basis declined over the planning period. On the other hand, our waste production on a per terawatthour basis increased over the planning period as did our use of the non-renewable resources, both gas and coal.

Q. All right. Turning then to you, Dr. Tennyson, I am going to ask you to review the cases from the four evaluation criterion in your area, and starting with the update case, the managed nuclear case.

DR. TENNYSON: A. The first criterion is employment and economic regional development.

There would be significant employment associated with the combination of CANDU 6, hydroelectric, Manitoba Purchase transmission and demand management programs, and significant regional economic development, particularly in less developed areas.

The second criterion is local community impacts, including special sensitive groups and lifestyle impacts.

There could also be significant potential

impacts from the in-migration of workers and their families for the development of hydroelectric and nuclear facilities. As indicated earlier, such impacts will vary according to project characteristics and the location, size, infrastructure, servicing capacity, character and past experience with development of local communities. As such, appropriate impact management measures would be developed to minimize and offset negative impacts and enhanced benefits.

With respect to the social acceptance of this case, as I indicated earlier, there is public support for demand management and its maximization prior to the commitment to new supply, and non-utility generation is considered an acceptable supply option by the public.

Although hydroelectric development is generally viewed as somewhat more benign than other supply options from an environmental perspective, concerns do exist about impacts on Aboriginal people on the one hand, whereas on the other hand it is seen as positive by others who are concerned about economic development.

For fossil fuel generation such as combustion turbine units, natural gas is preferred over oil and coal.

And as I indicated earlier, the nuclear option does remain controversial because of waste and safety issues, and it is seen to have some advantage over fossil because of concerns about global warming and acid gases.

With respect to the fourth criterion, distribution of risks and benefits, the local and regional effects of new facilities may be considered inequitable if there are no offsetting benefits.

With CANDU 6 there is the potential perception of inequitable risks such as health, safety and waste for residents in the vicinity of facilities, and the effects of waste management on future generations.

With respect to the demand management programs such as energy efficiency improvements in this case, programs for electrically-heated residences may be seen as inequitable by owners of homes with other heating equipment, and if demand management programs are unavailable or access is difficult for some groups, there may be inequitable costs and benefits.

Q. Now, how does the update fossil case compare to the case you have just discussed?

A. With respect to the first criterion, employment and regional economic development, as with

the managed nuclear case there would be significant employment associated with the combination of options, and it would also likely have comparable employment and regional economic development to the managed nuclear case.

With respect to the second criterion, local community impacts, as with the managed nuclear case there could be significant potential local community impacts from the development of new facilities for which appropriate impact management measures would have to be devised.

For the social acceptance of this case, it is similar to the managed nuclear case, and there is not that to choose between them except that concerns about the nuclear option would be replaced by fossil and IGCC concerns as outlined earlier.

There is also some uncertainty associated with Ontario Hydro's lack of experience with IGCC technology.

With respect to the fourth criterion, the distribution of risk and benefits, the local and regional effects of facilities may be considered inequitable if there are no offsetting benefits. In addition, though, this case does eliminate perceptions of risks to current and future generations associated

with the nuclear option.

Q. And how does the enhanced case compare with these previous two cases?

A. With respect to the first criterion, employment and regional economic development, it is similar to the managed fossil case.

The application of best available control technology would require substantial modifications to existing fossil stations and create employment which may offset the loss of employment for CTUs, and the advanced fossil would be small peaking units with limited local employment and regional economic development.

For the second criterion, local community impacts, as with the other cases there could be significant potential local community impacts, however, the local impacts from emissions at existing and future stations would be reduced.

For the social acceptance this case, as indicated in the results of the feedback program, there is support for environmental protection which is stronger than ever. The case may also help to address the growing concern over the use of fossil fuel until late in the planning period, and there is also public support for the use of alternative technologies.

With respect to the fourth criterion, the distribution of risks and benefits, minimizing emissions may reduce local perceptions of inequity.

Q. I would like to turn to you, Mr. Snelson. You indicated in your summary in dealing with Panel 2 that you would address the reliability of the Update Plan. What is the situation in that regard?

MR. SNELSON: A. The main conclusion is that the Update Plan does provide adequate reliability.

Mr. Taborek on Panel 2 discussed reliability based on Exhibit 87, and he showed that there was a need to balance the cost of providing additional reserve with the cost to customers if the supply of electricity is unreliable. The result this balance was a need for a reserve level of between 20 and 24 per cent, and with an associated unsupplied energy of about 10 system minutes.

Now, a 24 per cent reserve level was used in preparing the 1989 Demand/Supply Plans, and the Update Plans were also prepared using a 24 per cent reserve target, and this was applied in all years for the managed surplus plans, and Mr. Dalziel has already shown the degree to which the plans actually achieve that reserve. He has shown in his surplus capacity graphs that the managed surpluses cases are generally

within 1,000 megawatts and usually much closer than that to the desired level of reserve.

Now, the mix of options that are in the Update Plan are somewhat different to the mix of options that were in the 1989 Demand/Supply Plan and the studies on which Exhibit 87 was based. And so there is the theoretical possibility that a plan with a different mix of options may require a different level of reserve. And so we checked that for a representative case, one of the managed surplus cases, and the analysis showed that in all years the unsupplied energy was less than 10 system minutes, and that's the basis for our conclusion that this would provide adequate reliability.

Q. I would like to turn then back to you, Mr. Dalziel, and ask you to describe the cost of the update cases.

MR. DALZIEL: A. The cost of the cases are expressed as present value costs and they are the costs that are allocated to the planning period which in this case is 1992 to 2017, and they are expressed in present value 1992 dollars.

We will first look, if you turn to page 71 of the Exhibit 682, we are looking here at a figure of the cost of the cases that are the six cases that I

described earlier that are part of the Update, Exhibit 452, and these are cost comparisons relative to the lowest cost case.

There are six cases here, the update nuclear, update fossil and enhanced with and without the surplus management.

The three cases with the surplus management are on the left-hand side, and the three cases without surplus management are on the right-hand side.

The three points I want to bring to your attention with in graph, first is the update nuclear case with surplus management is the lowest cost case, and for that reason that's why it's shown as zero on the far left-hand side. So we are comparing everything else to that reference point.

We see though that the update fossil plan is very close or comparable in cost to the update nuclear plan cost.

The second point is that the enhanced case is significantly higher in costs, and this is largely a result of the additional level of environmental controls that have been applied in this plan, and to some extent also because it's using more costly fuels.

The third point then from this figure is that in all cases the plans with the surplus management, where surplus management has been applied, they are lower in costs than their corresponding case without the unmanaged surplus.

Q. I take it that the difference between the enhanced plans being somewhat less arises from the fact that the program of acquiring demand management resources and purchase NUGs is not in any way reduced under that proposition, would that be fair?

A. That's one of the reasons why its costs remain higher, yes.

Q. If we turn to page 72, here we are looking at the total customer cost of the cases, and this is now including the customer utilization cost as well as Ontario Hydro's costs for purchases and supplying the primary demand.

These costs are large. I won't go over this figure in detail. I just want to draw your attention to the -- we will start off with the total customer cost which is the second line from the bottom, and we see that the cost for the cases range from about $95 billion to $100 billion. But what I want to use this figure to point out is that about two-thirds of these costs are common to all of the cases.

If we move up one line from the total cost, which is the third line from the bottom, under the fuel category, the cost of the existing system allocated from 1992 to 2017, we see that that is a $50 billion cost that is estimated as being common to all of the cases.

Then if we move up three more lines, again under the fuel-related costs, the cost associated with existing demand, the existing level of demand, that's $17-1/2 billion and that's common to all of the cases. Those total to about $67-1/2 billion and that amount then is common to the cost of all of these cases.

I think it is more useful to focus on some of the cost differences between the cases, and that is shown then on page 73 of Exhibit 682. And here we are focussing on the cases with the surplus management assumptions, for the update nuclear, update fossil and the enhanced case.

Just looking at the bottom of the page then, we see the cost differences, that the update fossil is about $250 million higher in cost, compared to the update nuclear, and that the enhanced case is a total of about $4.2 billion higher in costs.

If we look up to the rows and columns

above that we can see some of the reasons for the cost differences.

First looking at the fossil case, we see that the lower capital cost, lower fixed OM&A associated with fossil options is saving costs relative to the nuclear option, but that this is outweighed by the higher fuel costs. So the net cost difference is the $260 million.

Moving over to the last column of the enhanced case, there are higher controls here, higher costs associated with emissions controls.

[2:22 p.m.]

In present value terms there are higher costs as a result of not reducing the demand management, the hydraulic and the purchase NUGs as part of the surplus management assumptions. There is also some higher costs associated with taking all of the supplemental energy associated with the Manitoba Purchase contract. Those are the main things that are contributing to the higher costs.

The fuel cost is also higher relative to the update nuclear but it's not as high as the fossil case largely because you will recall that the existing fossil system was not heavy utilized over the period 2000 to 2010. And so that's why its total fuel cost is

not as high as it is under the update fossil case, even though it's relying on fossil options in the long run.

Q. If I could come back to you, Mr. Shalaby. With Mr. Dalziel having outlined the various costs associated with the plans, I would ask you to address the avoided costs that result and that are associated with the 1992 Plan Update.

MR. SHALABY: A. The avoided costs associated with the Update are based on system incremental values that were filed as Exhibit 592. And that is one in a series of exhibits that include system incremental values starting with Exhibit 84, then Exhibit 85, Exhibit 175, Exhibit 309, and now Exhibit 592. And this is sort of like Rocky 5. This is a long sequel of if you have seen one, you have seen them all kind of deal.

The values we calculated in Exhibit 592 are assuming the managed surplus nuclear median case, so this is a case Mr. Dalziel described that uses combustion turbine units and nuclear facilities for expansion, median load growth and the surplus is managed.

I would like to explain that we found a decline in those values in the 1990s and early 2000s and that is primarily because of a reduction in load

forecast during that period and because of the reduction in the need for supply facilities. And the reduction in the need for supply arises because of the higher demand management and higher NUGs in that time period.

There is an increase at the tail end of the period and perhaps that's a good time to put up page 74. There is an increase towards the tail end because we use a CANDU 6 option instead of the Darlington-type option and the levelized cost of that is higher.

Page 74 really is a one snapshot description of avoided cost. We can use many, many more graphs. But this one is a combined power and energy. So, for a typical option that operates at 80 per cent capacity factor, it is project appraisal values. You may recall that we had planning values and project appraisal values. So this is one of two varieties, the project appraisal one.

And what I am showing on the graph is the three latest vintages. The March 1992 is in the solid line and then the August '91 and February '91 are the other two. And it's generally without comparing every two together, generally the solid line is lower in the early part of the period than either of the other two

and higher at the tail end of the period than either of the other two. And that is for the reasons that I explained.

Q. And what is the impact of the new values on the avoided cost of the kinds of typical applications that were discussed in Panel 3?

A. Perhaps I can turn to page 75 and we presented versions of this earlier that showed the progression of avoided costs with the different system incremental values. This now, here, has one more column at the end that captures the very latest ones.

What is on that table is the avoided costs for various typical options: the non-utility generation options that operate at three capacity factors; and the demand management R-2000 home is shown on the left-hand side as an option that is typical and evaluated; and high-efficiency motors; and at the very end the hydraulic Niagara River project is given as a typical project for comparison.

As we move to the right across the page, we show what the avoided cost is in cents per kilowatthour as produced in the DSP report and moving on with Exhibit 85 and then 175 and on all the way to Exhibit 592.

Again there is a large number of

comparisons that can be made, but to make a simple characterization of what is happening here we find that the options that are affected by the long term have risen in avoided cost, and those are typically the hydraulic and the demand management options, the R-2000 option for example. And the reason for that is that they start at a late period and go for a long period of time, so they capture an awful lot of the tail end period which is higher at this time.

The options that are affected more by the front end have gone down in avoided cost, so for example non-utility generation that is put in-service in 1994 has gone down in value.

Another observation is that the planning values have come down more than the project appraisal values. Typically the planning values are more sensitive to surpluses because they rely on how much the demand management affects the need for facilities. Project appraisal has a component in it that is less effected by the surpluses so it is more stable than the planning values.

So again to summarize the information on that graph, the non-utility generation values have come down since the more recent projections, particularly the planning values have, while hydraulic and R-2000

have gone up slightly.

Q. Have there been significant changes in the system incremental values -- really I guess what my question is: Have there been any significant changes in the system incremental values calculation methodology?

A. No, there have not been any significant changes. The long story we went through in Panel 3 remains largely in tact. There is one minor change that I would like to draw the panel's attention to and that is we did not calculate avoided cost or system incremental values for high load, low load and median load and then mix them in an expected value. We just calculated the median avoided cost or median system incremental value.

Our experience to date has shown us that the median resulted in information that is very much similar to the expected so we restricted the calculation this time to just median values.

Q. This presumably had the benefit of saving you some work.

A. It had that benefit as well, yes.

Q. And could you go on, please, and address the components of the integrated plan that are typically most affected by changes in avoided costs.

A. Well, the components that are most affected are the demand management plan, the non-utility generation plan, the hydraulic plan, and the Manitoba Purchase. Although that Manitoba Purchase is evaluated using avoided costs, not necessarily system incremental values, but as a secondary method the system incremental values will be used and Mr. Snelson will address the Manitoba Purchase later on.

Perhaps I can describe the impact on the other three: demand management, non-utility generation, and hydraulic. We discussed in Panel 3 how avoided cost is really both an input and an output of the planning process. And I showed in the diagram that had many feedback loops earlier yesterday how avoided cost results at the end of a plan and then gets fed back to the beginning of the plan.

And we promised in Panel 3 that when we came to this stage of the hearing we will show you how the avoided costs are consistent in an integrated way. So that this is the time and this is the stage where we show how the avoided costs are consistent with the integrated plan that we put together. And that's what we call closing the loop.

Q. What is the impact of the change in avoided costs on the potential for demand management,

non-utility generation, and the hydraulic generation. And I guess I would ask you to start with demand management.

A. There is little impact on demand management and there are two reasons for that. One is that the avoided costs for demand management picks up system incremental values starting in the year 2001. We went into a detail of that in Panel 4. And starting that period, skipped much of the reduced values that were there in the 1990s. So, the total impact is negligible.

The second reason the demand management plan is not affected very much is that we find that many measures in the demand management program have a life cycle cost that is below, sometimes significantly below the avoided costs. And we don't find very many problems that are slightly above avoided costs. So small changes in the level of avoided cost neither drops a large number out of the running nor does it bring in a large number into the realm of economics. So, the potential for demand management is not very sensitive to small changes in avoided cost.

For those two reasons we find the demand management plan to be unaffected by the recent changes in avoided costs.

Q. And how about the impact on non-utility generation?

A. There is more significant impact on the economics and viability of various non-utility generation projects. And that's particularly because the values in the 90s have come down and many of the non-utility generation projects are evaluated in terms of the 1990s avoided costs.

Our expectation is that major supply NUGs will probably by significantly affected particularly if the planning values are used.

Now this reduction in the viability of particular projects does not affect Hydro's NUGs plan significantly. And the reason for that is that a considerable portion of our NUG targets is already secured. It is either already in place, operating producing electricity, or it is under construction or committed for construction soon or is grandfathered for further discussions. Discussions started some time back and there has been a consideration of re-examination of project viability but perhaps under conditions that prevailed at that time.

So while there are impacts on new uncommitted facilities, we really have secured a good portion of our target already and for that reason we

feel that our NUGs plan is secure and we can, if needed, achieve the NUG target that we set for ourselves.

Q. And the final matter you were going to address was the hydraulic generation potential.

A. The hydraulic generation experienced an improvement in cost/benefit ratios. Again because it is relying more and more on the tail end of the avoided costs and the system incremental values have risen in that time period. I would like to refer to page 76 which is taken out of a response to Interrogatory 10.42.23. This is an extract from that interrogatory response.

THE REGISTRAR: That would be 683.2.

---EXHIBIT NO. 683.2: Interrogatory No. 10.42.23.

THE CHAIRMAN: Thank you.

MR. SHALABY: And on that chart we see the various hydraulic sites that were evaluated in Panel 6. We see their levelized avoided cost on the first column and their levelized unit energy cost. So, their benefits is in the first column if you like and their cost is in the second column; and if you divide one by the other, the cost/benefit ratio is shown on the third column.

And there is an improvement. For

example, Big Chute, which is the very first line, shows a cost/benefit ratio of .71. If you go to the Exhibit 359, which this is an update of, you would find that that ratio was .77 the last time we presented these numbers to the panel. So there has been an improvement from .77 to .71. Likewise all the other ratios have experienced an improvement.

MR. CAMPBELL: Q. Overall then, what conclusions do you draw with respect to the impacts of the new avoided costs on demand management, non-utility generation, and the hydraulic portion of the plan?

MR. SHALABY: A. Well, I draw two conclusions. One is that the system incremental values and avoided costs are sufficient to support the plans and the targets that we set for ourselves. There is indeed sufficient economics for both the demand management and the hydraulic programs and also for the non-utility generation. So there is sufficient incentive there to achieve the targets that we set for ourselves.

The second conclusion is one of great interest to planners in sort of the science of integrated planning, and that is that the plan is now self-consistent and integrated and fits together in a harmonious and consistent manner. So, the more

practical one is that we have enough incentive to get these three plans under way.

Q. Now, Dr. Long, I would like to turn to you, please. And before getting into the details of, the financial results associated with the updated plans perhaps you could take a moment to explain why the financial results that are given have been presented on a 20-year basis rather than on a 25-year basis. I understand this is a somewhat different circumstance in case of your area.

DR. LONG: A. Yes. And I am sure that it is something that people have noticed both in the original DSP document as well as in the Update. And in fact it was explained in Exhibit 3, the original DSP document, at page 15-61. And perhaps I can take a moment to explain the reason here.

The reason for the difference in time frame is that the determination of financial results associated with any demand/supply plan requires the definition of a system plan several years ahead. And this is because in any given year the cash flows which are a determinant of the financial results are in part due to facilities that will be coming into service several years down the road, so this requires that projections of corporate financial results lag the

definition of system plans.

Q. Could you speak then please to the financial outlook under the Update Plan, perhaps first turning to the rate impacts.

A. Yes. And the next overhead which is page 77 of Exhibit 682, which is actually a reproduction of figure C-6 from the Update, Exhibit 452, shows the projected real rate index for the three update cases. And this rate index has 1991 as a base. As I mentioned it's a real index. Inflation has been removed. The escalated price index has been deflated by the forecast CPI to produce this chart.

The first point that I would ask you to note is that for all three plans over the period '91 to '94, there is about a 20 per cent real increase in the price index. I should also note that the latest short-term price outlook which has recently been filed as part of Hydro's 1993 rate submission at the OEB shows a similar outlook but one which is slightly lower.

[2:40 p.m.]

I would also ask you to note that for the update fossil and update nuclear cases there is very little difference in the projected rate outlooks. For most of the period beyond 1994, for both of these cases

we see little real increase in the electricity price, and there is some real increase towards the tail end of the projection period and this is due to the new facilities, major supply facilities coming into service.

In the case of the enhanced plan, this shows median term rates in the period of the late 1990s an early 2000s which are higher than the other two cases, in fact higher by up to about 10 per cent, and this is due mainly to the accounting costs associated with the additional environmental controls included in this case.

Q. Now, could you please explain why the change in rate outlook has occurred from the time of the preparation of the 1989 plan?

A. Yes, the long-term rate outlook that I have currently shown you, being consistent with the update, is significantly higher than that that was projected at the time of the original Demand/Supply Plan.

There had been a number of factors which have contributed to this increase, however apart from the effect of the increased targets for demand management and non-utility generation program which have added between 5 and 10 per cent to the rate

outlook, this change in rate outlook has little to do with the changes introduced in the Update Plans.

Some of the factors contributing to the increase should have been enumerated in Interrogatory 11.2.2 --

Q. Perhaps we can stop and get a number for that.

THE REGISTRAR: 11.2.2, is .3, 683.3.

---EXHIBIT NO. 683.3: Interrogatory No. 11.2.2.

MR. B. CAMPBELL: Thank you, Mr. Lucas.

Q. You are saying these are dealt with in part in that interrogatory?

DR. LONG: A. Yes, some of the factors include a lower forecast of inflation, higher projections in capital program costs which have come through Hydro's business planning process, lower forecasts of nuclear generation, somewhat higher net income targets, higher pension costs which are factored in the Corporation's operating costs, as well as the introduction of some cost allowances.

As I said, the effect of these factors is largely independent of Hydro's longer term plans to balance supply and demand, meaning that this outlook for higher prices would be an underlying feature of any alternative for dealing with future supply and demand.

Q. Now, what about the borrowing impacts of the Update Plan?

A. It's the next overhead, which is page 78 in your package, which again is a reproduction of a figure from Exhibit 452, this time it's from figure C-7. This shows the projected borrowing requirements for each of the three plans expressed in 1991 dollars, again we have taken escalated borrowings and removed inflation using the consumer price index.

I would also note that what is shown here is Hydro's gross borrowing requirements under each of the plans, that is it includes the effects of ongoing refinancing requirements.

For each of the plans the borrowing level for about the next 15 years is in the range of $2 to $4 billion dollar, and then it moves up to around $5 billion towards the end of the period and this due to the funding requirements associated with major supply.

These borrowing levels are similar to current borrowing levels which have been successfully managed by Hydro.

For the enhanced case, during the 1990s borrowing is up to about half a billion dollars per year higher than the other two cases, and this is due to the additional funding requirements associated with

environmental controls.

During the next decade, the enhanced plan shows a borrowing requirement very close to that of the fossil plan, and both of these plans are below the update nuclear plan, and this is due to the fact that the nuclear options have a higher capital cost than the fossil options.

On a cumulative basis over the 20-year period as shown here, the update nuclear plan has a cumulative borrowing requirement, which is some $7 billion higher than the update fossil case, and also the nuclear plan is about $4 billion higher in borrowing requirements than the enhanced plan.

Compared to Plan 15 in the original Demand/Supply Plan, the update nuclear plan shown here has a cumulative borrowing requirement which is about $9 billion lower, and this is mainly due to the reduced requirement for major supply in the Update.

Q. From a financial viability viewpoint, how would you characterize the updated plans both nuclear, fossil an environmentally enhanced? Perhaps could you deal both with the managed and unmanaged surplus at the same time.

I have to take a brief pause here. Some notes have been lost.

A. From a financial planning perspective, each of the plans is considered viable, and what I mean by that is that the rate and borrowing outlooks associated with the plans are judged to be manageable.

Once the short-term rate increases that I have indicated have been implemented, both the nuclear and fossil cases are similar in terms of their rate impact. The projections show no real rate increase until major supply is added, and this is expected to be a manageable situation.

In the case of the enhanced and unmanaged surplus cases, these are both expected to result in higher median term rates than either the update nuclear or the update fossil cases, and this is judged to be a less desirable situation from a financial point of view.

In the case of the enhanced plan, this is something that had to be weighed against the benefits of the plan, and in the case of the unmanaged plan, the higher rates represent an incentive to actually manage the surplus.

The borrowing requirements for each of the plans as I have mentioned is in the order of 2 to $4 billion over much of the planning horizon and this

is similar to levels that have been achieved in the past by Hydro and are therefore judged to be manageable.

Q. All right. Now, Mr. Snelson, I want to turn back to you and move away from the monetary side and towards the transmission side, some of the transmission considerations that affect the comparison, and ask you to briefly outline or describe how you would like to deal with the transmission considerations that have an effect with respect to the Update Plan and its evaluation.

MR. SNELSON: A. You can divide the transmission considerations up into two time periods. The first one is before major supply is required, which is now prior to about 2009, and the other period is after major supply is required. So you could deal with it in those two ways.

Q. I am going to ask you to deal with the farther out one first, deal first with that period after major supply is required.

A. That's an area that has much less significance today than it did in 1989 because it's now further out into the future.

We have considered the interaction between transmission and major supply additions in two

areas, one area is with respect to radial transmission that is required solely for a particular generation option, and the other is that major supply can affect the requirements for inter-area transmission.

As I have said, this is less significant than it was in '89 because the period is later and there are now fewer megawatts of major supply required.

The way this is handled is that it is included in the cost evaluations that have been described by Mr. Dalziel, and we have used the same methods as were described in Exhibit 3 and Exhibit 6.

The radial transmission and the impacts on inter-area transmission have been determined based on some illustrative assumptions with respect to siting. I think Dr. Macedo in Panel 7 will have indicated that you can't say anything very specific about transmission until you start to make some assumptions with regard to siting.

So we have made illustrative assumptions and that enables us to have a high degree of confidence that we have captured all of the costs.

Q. All right. Now, I would like you to come back then to the closer period, that is the time before additional major supply is required.

A. This is the period which is now

assuming greater importance because of the nature of the Update and the options that are being relied upon.

As was discussed by Dr. Macedo in Panel 7, there are five major inter-area interfaces that may constrain the development of resources, and these are of likely to need upgrading for some combination of load growth, the distribution of generation on a geographical basis, and that includes the distribution of non-utility generation, and there are also some technical considerations that have to be taken into account.

The transmission considerations were quite significant in the integrated consideration of flexibility.

The Update Plan relies on short lead time generation to provide some of the flexibility that is required; however, that is not matched by short lead time transmission options, and so it is necessary to take some actions to maintain transmission flexibility to be able to match the flexibility that we are relying upon from generation.

Q. And that brings us I think directly to a question put by the Chairman during the course of Panel 7 cross-examination, and I think there was an occasion on which the Chairman even indicated that his

own question might be more pertinent to Panel 10. The question can be found at Volume 106 at page 18705, and really I think quoting from that area of the transcript, the question was this:

Do you do you have adequate transmission to meet the various contingencies that the present planning process seems to envisage?

A. Yes, we believe that existing and planned transmission will be adequate and that is based on Dr. Macedo's evidence and considerations related to the Update Plan.

Dr. Macedo indicated that some transmission plans in the 1990s were being advanced to reinforce those five interfaces, and these were areas where additional approvals were not required, and that we would include in our plans somewhat earlier implementation of those options to those improvements to provide additional flexibility.

In addition, Dr. Macedo indicated that we would continue with the approval processes for major transmission. So even though we are not continuing with approval processes for major supply additions of generation, we are continuing with approval processes for major new transmission lines associated with

upgrading those interfaces.

Once the transmission approvals have been obtained, then the construction lead time of major transmission lines is of the order of three to four years, and that provides a reasonable match with the sort of shorter lead time generation options that we are relying upon such as combustion turbines and large non-utility generation.

So when we have reached that stage, then we will have transmission flexibility that will be comparable to the flexibility that we are relying upon from short lead time generation options.

With respect to radial transmission then, it has always been our position, and it continues to be, that we will seek a approval of radial transmission associated with specific generation options as part of the approval process for those generation options. And, for instance, in this particular process, we are seeking a approval for the need and rationale, for the radial transmission associated with the hydraulic capacity that is in the attainable potential.

So overall we believe we can maintain adequate transmission provided the transmission planning and approval processes continue.

Q. I want to turn to another area then

with you, Mr. Snelson, and that has to do with the area of flexibility of the Update Plans. I would ask you to explain, please, what Hydro means when it speaks of a response portfolio.

A. The response portfolio is a name that is given in Exhibit 452, which is the Plan Update, and it deals with the planning responses that are available to deal with identified planning uncertainties.

Mr. Shalaby in our evidence has already discussed some of the aspects of planning around the median and how that requires examination of the risks that we face.

And judgments have to be made whether the response portfolio, the options that are available to us, provide sufficient coverage to cover the identified risks without requesting major supply approvals at this time.

Q. What is the response portfolio that is it associated with the Update Plans?

A. That is given on pages 28 and 29 of Exhibit 452, and in particular page 29 of that exhibit, which is reproduced as page 81 of Exhibit 682, and that is now on the overhead, this gives a table with the heading of Sample Response Portfolios.

This is called a sample. It does explore

a wide range of risks that we face, but it doesn't necessarily include all of the possible risks or all of the possible responses.

We do believe, however, it's sufficient to provide some aid in judging whether the range of responses is likely to be adequate.

I am not going to discuss every block of this table, but I would ask you to note that several of the risks that are identified in the middle column have similar results in that they tend to increase or decrease the need for demand or supply resources. For example, uncertainty in demand management and NUGs, which is the top box, affects the need for other demand and supply resources. Similarly, uncertainty would be associated with the life or performance of existing plant, which is the second box, also affects the need for resources.

And about two-thirds of the way down the table is an element called plan to the median with risks of load forecasts being above the median or load forecasts being below the median, and uncertainties in the load forecast also clearly affect the need for resources to either increase them or decrease them.

In the discussion that generally follows, we will deal with upper and lower load growth because

we believe that to be the dominant uncertainty.

The flexibility that is provided to cover upper or lower load growth will also provide flexibility to cover off other risks and other uncertainties that affect the need for resources.

And so while we may not in our evidence be explicitly dealing with those other uncertainties, then we are implicitly dealing with them because they are implied when we are talking about how we would respond to upper load growth or lower load growth.

These risks that affect the need for resources, if the effect is in the direction of increasing the need for resources, then the sorts of measures that are included include maintaining the resources that would be reduced by surplus management. That sounds a little bit like it's a double negative but it's a key element in the strategy.

By choosing to carry through on the management of the resources that would be managed in the surplus management cases, then we can have coverage of a large part of the risk of upper load growth.

[3:02 p.m.]

And that's why it is a key element in our strategy to delay making decisions on specifically how to and how much to manage the surplus until a decision

has to be made. That's why that is a key part of our strategy to preserve the flexibility to have those resources if they are required to meet upper load growth. Other elements of meeting additional resources would include more non-utility generation or combustion turbines.

Risks that reduce needs tend to be dealt with by measures such as deferral of new plant or mothballing existing plant.

There are other categories of risks in the table which are associated more with costs than they are with the amount of resources that are available. For instance, there is a risk identified of higher natural gas prices. There is a risk identified of higher costs for life extension. In these cases the responses tend to be shifts to other resources that are less affected by that particular cost risk, and access to a diverse set of resources helps to reduce one's dependence on any one particular element.

The plan that we have relies for additional resources mostly on demand management and non-utility generation, much of which will be gas fired. The hydroelectric options that we are seeking approval of and the Manitoba Purchase with its associated transmission provide important additional

diversity.

Yet another category of risks are associated with the environmental performance or environmental requirements. And, for instance, increased regulatory requirements is identified as a risk for the existing system.

In addition, there is another risk of the possibility of poor performance of control equipment. In this case the response tends to be such actions as increased environmental controls or shifts to fuels with lesser emissions or greater reliance on resources that are less subject to that particular emission concern.

And if, for example, the concern is air emissions such as acid gas or carbon dioxide, then the hydroelectric and Manitoba Purchase options are important in reducing the use of fossil fuel.

Q. Now what do you see as the main factors that have changed since 1989 to cause Hydro to judge that the response portfolio is adequate at this time?

A. There are two main changes. The first one is quite obvious and that is that the existing system, the Manitoba Purchase and the preferred options are now forecast to meet most of our

needs even under upper load growth in the 1990s.

The second factor is the low natural gas prices and lower forecasts of natural gas prices for the future. This tends to reduce the economic penalty of relying on short lead time options and it is also stimulating the major supply non-utility generation which also has short lead time.

Just to bring out the significance of that latter point. If we were to get to the point where our short lead time options were also to be our lowest base load -- sorry, were also to be our lowest cost base load options, if we were to reach that point, then the tension between planning for flexibility and planning for low cost would disappear. The lowest cost option would also be the most flexible option.

Now, we do have indications at the moment through -- and no amount of major supply non-utility generation is being offered, fueled by gas, less than avoided cost, that with current gas prices, then people are able to get gas contracts that approach this point.

And so it suggests that with current gas prices there is little penalty in relying on short lead time options. We do however forecast that the natural gas price will increase to some degree and that has been part of our evidence on Panel 8, so we don't

expect this situation to persist forever. But the bottom line is that today we have much less incentive to seek approval for long lead time options because the shorter lead time options don't carry the same cost penalties they seemed to carry a few years ago.

Q. Now, Mr. Dalziel, against that background I want to come back to you and ask whether you have given consideration to the kinds of steps that would be taken and sort of put together cases that look at the situation should the lower and upper load forecasts actually materialize?

MR. DALZIEL: A. Yes, we have looked at some cases. We regard them as illustrative cases in that there are many different ways that you could meet the upper or lower load forecast. These cases have been described in Exhibit 646 and are under attachment D.

Q. Could you go ahead and describe those, please.

A. I will begin before I get to describing what the cases are actually composed of, I will have a look at the new major supply requirements under the upper, median and lower load growth, and that's figure 82 of Exhibit 682.

And before I get into describing the

cases then, there are a couple points from this figure that are worth pointing out. The first is that under the lower load forecast condition, there is no new major supply requirement, so that's why we see no line with respect to the lower on this figure.

The other point is that the gap between the upper and the median has now been increased slightly compared to the earlier figures I was showing and that's because we now have life extensions as part of the Update. The life extension does not change when you would need major supply facilities in the early years under the upper load forecast, but it does shift the median requirements back by about a year. So, looking at the use of a base load station, for example, you could use one in around the year 2001, 2002. But under the median condition now that's out at least 8 years and then even much further beyond that under the lower load growth condition.

I will briefly describe then the capacity that is required under the upper load growth condition; and to do this, I will just compare or summarize the capacity relative to the update nuclear under median load forecast. And page 83 summarizes this.

Before I get to the major supply requirements, I will just remind you that the demand

management component, the purchase non-utility generation component, and the hydraulic option would be at their forecast values in that there is no surplus under the upper load forecast, so these options would all be in without any surplus management assumptions.

In total there would be an additional 5,700 megawatts of CTUs added under upper load forecast and they would begin to be added by about 1996. And we recognize that these could either be Ontario Hydro CTUs or they may well be CTUs provided by NUGs.

We have the IGCC base load stations and there is a total of 7200 megawatts assumed in this case and they begin coming into service around the year 2006. And with their shorter lead time, then we have more base loads stations coming into service prior to 2010 and the net result is that when we look at the amount of CANDU stations in this upper load forecast case, that there is eight units instead of nine units that there were in the median load forecast case and that's simply because we have, by the end of the plan period, enough base load stations being provided by the mix of CANDU and IGCC. So relative to the update median case, there is one less CANDU in this illustrative case of meeting the upper load forecast.

In total then there is an additional

12,291 megawatts being added to provide a reliable means of meeting the upper load forecast. In addition some acid gas control measures have been advanced, depending on which station you are looking at, by one to five years. And also the Lakeview units are not removed from service until their retirement date.

Also in the earlier years around 1995, we have assumed that the 800 megawatts at the Hearn station and 100 megawatts at Thunder Bay Unit 1 could be returned to service; again that capacity may well be provided by non-utility generation under an upper load forecast condition.

Q. I take it you have done the same kinds of energy modelling for the upper?

A. Yes, we have. And if we turn to page 84 of Exhibit 682, I will try and go over this quickly. This is following a similar format of the energy production simulation that we looked at earlier for the update cases under median load forecast.

The top figure is the energy production under the upper load forecast and the bottom one is the lower. But dealing with the upper first, the top line corresponds to the basic load forecast under the upper load growth condition. And then working up from the bottom, the Manitoba Purchase is contributing about 7

terawatthours towards the end. Again the hydraulics are contributing about 39 to 40 terawatthours.

The existing nuclear system behaves much the same way as it did under median load forecast and it's about 95 terawatthours over much of the plan period but declines to 55 terawatthours at the end.

The new supply. In this illustrative case, we have assumed a combination of IGCC and nuclear facilities. The new nuclear facilities are providing about 40 terawatthours by the end and the new fossil facilities, the CTUs and the IGCCs are providing about 54 terawatthours by the end. And the existing fossil system is being worked to the extent of 42 terawatthours by the end.

Just to put some of that component, the nuclear and the fossil, into some comparison, by the end of the plan period in this case, the total amount of energy coming from nuclear would be about 95 terawatthours and there would also be about 95 terawatthours coming from the new fossil and the existing fossil.

The purchase NUGs are providing 25 terawatthours by the end of the plan period and the demand reducing options are saving 35 terawatthours.

Before I go on to look at the energy

production results under the lower, maybe we will turn to the next page in Exhibit 682 and look at the use of the oil and gas fuels under the upper load forecast.

The top figure is showing the oil energy production. And as I mentioned earlier, when it comes to simulating the use of CTUs we have assumed that they would utilize oil but we recognize that it could well be a combination of oil and natural gas.

But up to the year 2000 that is reflecting the use of the Lennox station. And then beyond the year 2000, it is largely a combination of the Lennox station and the CTUs that have been added. The majority of the energy is being provided by the Lennox station and there is about, I think about 5 to 10 terawatthours, depending on the year that we are looking at, that would be provided by the oil in the CTUs. And again some perhaps 2 to 4 terawatthours of that energy may well be produced by natural gas.

Some of the further details on this information is provided of course in the case summaries under Attachment D of Exhibit 646.

The lower graph on this page is showing the use of natural gas to produce energy. And the natural gas is used at the Hearn station from 1995 to the year 2000, and we would assume that the Hearn

station would be retired in the year 2000. And we see that it is producing a very small amount of energy so that the Hearn facility is really providing, more important for providing capacity in that period rather than being a workhorse for energy.

The use of natural gas in the year 2000 and then the year 2002 to 2009 is gas that would have to be used in place of energy produced by our unscrubbed coal units, namely, the Lakeview Station, in order to result in the acid gas emissions that are predicted for this case. And Ms. Howes has some information that she may be showing us on the acid gas emissions. So that's the natural gas that would have to be used over those particular years to help ensure that we are achieving the kind of acid gas emissions that we are looking for.

If I can just back up then to page 84, the energy production results under the lower load forecast, again there was no new major supply added in this case so we are relying on our priority and contract options as well as the existing system.

The Manitoba Purchase is providing again the 7 terawatthours. The hydraulic program is providing 39 to 40 terawatthours by the end of the plan period. The existing nuclear system is producing a

little bit less energy over the middle years of the plan period because this is a lower load forecast condition. They don't have to work quite as hard.

Again though by the end they are producing the 55 terawatthours. The existing fossil system we see has really been diminished in its role of providing energy over much of the plan period, but by the end it's back to providing 35 terawatthours comparable to today's use of the fossil system.

Because this is a lower load forecast case, we have applied some surplus management assumptions here and this is reflected in the lower amount of energy over purchase NUGs from a good portion of the plan period, but again by the end of the plan period they are back to providing 25 terawatthours. And likewise the demand reducing options have been reduced in the early years of the plan period, but they too are restored to forecast levels by the end of the plan period and are saving 35 terawatthours.

Q. I take it you have also prepared costs for these two cases?

A. Yes, we have. If we turn now to page 86 of the overhead package, Exhibit 682. Again the total cost for these cases are provided in the Exhibit 646 in attachment D. I think for here it is just

adequate to give a comparison to the update nuclear with the surplus management. That's the one that we are comparing it to.

And under lower load forecast, as we would expect, there is a much less -- year by year the primary demand is much lower. No new major supply options are required and as a result this case would cost about $14-billion less than the update nuclear with the surplus management assumptions.

Then looking to the upper primary demand, basic demand is much higher and we are also having to add a substantial quantity of new major supply requirements, so it's not a surprise that this costs much more, to the extent of about $23 billion.

[3:22 p.m.]

Again, these are in present value costs, 1992 dollars, and costs that are allocated to the planning period.

Q. Now, just before we move on to deal with the natural environmental impacts associated with the upper and lower cases, I want to ask you, Mr. Dalziel, to just briefly remind us of what is the chance of being on the upper load forecast end of the bandwidth?

A. The upper load forecast is chosen to

be the 90th percentile of the load forecast bandwidth. So over the long run there is a 10 per cent probability of the upper load forecast occurring.

However, in the short-term we know that the probability of that occurring at this time is less than 10 per cent. I say that because if we look into the details of the load forecast as described in Exhibit 467, that update predicted a January peak of about 25,800 megawatts, and we have just been through our winter of 1991/92 and our actual winter peak this paths year was 23,500 megawatts, and the difference then is 2,300 megawatts, and so right now we are about 2,300 megawatts below the starting point of the upper load forecast.

So in the short-term, we know that the probability of being on the upper load forecast is less than 10 per cent, but in the long run it still remains a 10 per cent probability.

MR. B. CAMPBELL: Mr. Chairman, I don't know when you intend to take the afternoon break, I think this would be as convenient a time as any. I am also mindful of course of the desire to finish by five.

THE CHAIRMAN: We must stop at five in any event because one of us is catching a plane.

MR. B. CAMPBELL: We will spend some

useful time in the break then.

THE REGISTRAR: Please come to order. This hearing will take a 15-minute recess.

---Recess at 3:25 p.m.

---On resuming at 3:40 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Be seated, please.

THE CHAIRMAN: We seem to be losing some of our audience.

MR. B. CAMPBELL: I can't understand it. [Laughter].

Thank you, Mr. Chairman.

Q. I want to come back to you, Ms. Howes. With respect to the upper and lower load forecasts, and I want you to -- I guess actually it's the upper. I would really like you to focus on the upper and describe how that case compares on the various items that you have used throughout.

MS. HOWES: A. Similar to Mr. Dalziel, I compared the natural environmental effects of the upper against the update nuclear which is the median load. I will first be referring to figure 87.

I just want to spend a few minutes on this one just to explain what exactly we are looking at. There are three bars on these graphs, you are only

to focus on the first one which is the update nuclear and the last one which is update upper, so it's the first and the third.

So a quick check across this graph suggests that what --

THE CHAIRMAN: I am sorry, I didn't quite follow that. Do that again, please.

MS. HOWES: The first bar is the update nuclear and the third bar is the upper.

THE CHAIRMAN: What is the middle bar?

MS. HOWES: That's no approvals, and I will hold that until later.

THE CHAIRMAN: What does that mean?

MR. B. CAMPBELL: We get to that a little later in the evidence.

MS. HOWES: It's a little later.

MR. B. CAMPBELL: We will come to that.

MS. HOWES: Yes. So for this discussion just focus on the first bar and the third bar. So what we find is that for hydraulic purchases and nuclear there is no difference between the update nuclear and the upper. However, under coal you will see that there is significantly more coal use for the upper, significantly more oil and higher NUGs for the upper relative to the update nuclear.

MR. B. CAMPBELL: Q. While Ms. Howes is getting herself organized to move through the balance of the charts, I will opine, Mr. Chairman, that I do agree that the no approvals portion of that doesn't make a lot of sense. That is certainly our position on the matter.

THE CHAIRMAN: I think I know what it's meant to mean but I just wanted her to tell me.

MS. HOWES: I will, I will.

MR. D. POCH: The preferred update and the next update.

MR. B. CAMPBELL: Q. If you could proceed, please.

MS. HOWES: A. The first one I would like to focus on is figure 88. And again what you are to consider in this one is, the first, the update nuclear, which is the line with the little black square and then the update upper which is the line with the star.

When you compare these two, you find that obviously the upper has higher $SO_{(2)}$ emissions relative to the update nuclear, and you will find that in about the year 2004 the upper exceeds the dotted line, and if you remember from my previous evidence, this is the possible regulation line that I had discussed

previously and it's about 90 gigagrams. So beyond the year 2004 there would be difficulty in terms of SO(2) emissions relative to meeting possible regulation.

If I could move on to the next one, figure 89, which focuses on NOx production. Again, we are looking at the line with the star and the line with the black square.

The dotted line on this particular graph are the targets that I discussed in my previous evidence. In the period 2000 to 2005, the dotted line refers to a 38 gigagram target. From 2005 to 2017 it refers to 25 gigagram target.

There are obviously higher NOx emissions for the upper plan relative to the update nuclear and in the year 2010, the emissions of NOx from the upper would exceed the possible target line.

If I could move on to the next figure, which is figure 90, total CO(2) production. The dotted line on this particular graph refers to the possible limit that I alluded to before for CO(2), that is a 25 teragram limit. You will see that from the year 2000 onwards the upper would exceed this possible CO(2) limit.

The major reason why the upper would result in higher air emissions is because of the

increased use of the existing fossil station, there is more reliance on oil-fired CTUs and there is an inclusion of IGCC's in the upper as part of the base load and that's of course relative to the update nuclear plan.

In these plans as well trace elements and particulates would be significantly higher in the upper plan relative to the update nuclear plan.

Q. That's shown, I gather, on pages 91 and 92.

A. Yes, that is.

Q. I think they are relatively self-explanatory.

What about water use?

A. Water use is shown in the next figure, figure 93, and it too is quite explanatory. The water use is higher in the upper relative the update nuclear plan.

Q. I take that would also be the case with respect to waste production, and the figures for that are shown on figures 94 and 95?

A. Yes. And as you would expect, the waste production in the upper would be higher than for the update nuclear plan.

Q. And how about radionuclide emissions?

A. Radionuclide emissions are similar between the update nuclear and the upper planned.

Q. And with respect to fuel and land use?

A. As is seen in figure 96, coal use is significantly higher with the update, or with the upper plan over the update nuclear plan.

Similarly, oil use and natural gas use would be significantly higher in the upper relative to the update nuclear plan.

The amount of uranium use would be comparable or reasonably similar in the plans because the number of nuclear units is relatively similar.

But before we move on I would like to correct an error in Exhibit 452G.

Q. This is 452G?

A. Yes, 452G.

Q. Mr. Chairman, rather than have everybody find it and turn it up, I am going to ask Ms. Howes to describe it and if people would be sure to make the correction on their document later, I would appreciate it.

A. On pages 48 and 49. 48 shows oil use. The oil use figure shows values that are too high and the total gas use figure which is the figure on

page 49 shows gas use that is too low.

Mr. Dalziel has noted that there could be some increase in gas use for his particular -- or for the upper case, and figures that he was using are 2 to 4 terawatthours more use of gas for the upper in the period 2005 to 2017, and that does not show on that particular graph.

2 to 4 terawatthours of natural gas use is probably equivalent to about 1 cubic gigametre of gas use.

This should not materially affect the environmental information that we have. We assumed that it would be oil rather than gas, and from an environmental point of view gas is preferred over oil, and we probably exaggerated slightly the wastes and air emissions and water use of the upper plan, but as I said, it's not a material difference.

Q. Dealing with land use.

A. The land requirement for the upper is somewhat higher than the land required for the update nuclear because of the additional land required for additional generation and ash disposal.

Q. So overall?

A. So in summary, as you would expect, there are more emissions, more effluents and more waste

generated by the upper. When one compares it to the update nuclear plan, the radioactive emissions and the radioactive wastes and uranium use are very similar between the two plans.

Q. And turning to you, Dr. Tennyson, how would you compare the upper load case with the median update plans?

DR. TENNYSON: A. As you would expect, the upper load case would have the most benefits in terms of the greatest employment and regional economic development with both new nuclear and IGCC facilities, with the corollary that there is also the greatest potential for significant local community impacts as a result of the siting and development of more new facilities requiring impact management measures.

For the social acceptance of this case there would be the greatest number of concerns because we have both nuclear and fossil options.

And with respect to the distribution of risks and benefits associated with this case,there is the greatest potential for equity concerns because of more new facilities and the inclusion of nuclear facilities.

Q. And Dr. Long, turning then to you, would the financial outlooks of the kind that you have

described for the median forecast change under the upper and lower scenarios?

DR. LONG: A. A formal corporate financial impact assessment was not prepared for the illustrative upper and lower load growth cases. However, I can describe the expected impacts based on past experience of assessing such cases, including those in the original Demand/Supply Plan.

I will start first with rates.

Under the upper load growth case, where we are selling more electricity than under the median case, short-term rates are expected to be lower and this is because the additional revenues resulting from the higher demand will more than offset the additional fuel costs. In the longer term however, the costs of new generation and transmission facilities needed to meet the higher demand are expected to eventually result in higher rates than under the median case.

For the lower load growth case, the rate impacts are expected to be opposite to those for the upper, and under this case we are selling less electricity and in the short-term the reduced revenues, the effect of the reduced revenues, is expected to result in higher rates, their effect being only partially offset by lower fuel costs. And in the

longer term for this case rates are expected to be lower due to the effect of the deferral of transmission and generation facilities.

As for borrowing under the upper case, borrowing levels are expected to be higher due to the requirement to fund new facilities required to meet the increased demand and once again under the lower case, the effect is expected to be opposite, under this case reduced borrowings are expected due to the deferred need for new facilities.

Q. All right. Now, I want to come back to you Mr. Snelson, and turn to some discussion of the Manitoba Purchase aspect which, of course, is related more directly to the particular approvals being requested and I would first ask you whether the economics of the Manitoba Purchase have been re-evaluated based on the updated Plan?

MR. SNELSON: A. Yes. They have, and the results have been given in transcript undertaking which is Exhibit 442.7.

Q. And has that evaluation been done using the same methodology as the evaluation described by Mr. Huggins on Panel 7?

A. Yes, the methodology is the same full system simulation methodology which is comparable to

the full system simulations we discussed in Panel 3 and the same as discussed by Mr. Huggins.

One slight difference in the application of that methodology is that consistent with the Update Plan, both the plans with and without the purchase aimed for significantly less acid gas emissions. And this effects the costs of acid gas controls and essentially the models of the plans with and without the purchase were adjusted to have the same acid gas emissions and this was done throughout the time period whereas previously it had only been done if we were approaching the legal limit. The result of this is to give full credit to the Manitoba Purchase for reducing acid gas emissions, even if the reduction is a reduction below the current legal limit.

Q. And that is consistent with the approach taken in the Update with respect to environmental controls generally?

A. We believe that is consistent with the increased emphasis placed on environmental controls in the Update Plan.

Q. Can you outline please the results of the evaluation?

A. Yes. The results are summarized on page 98 of Exhibit 682, which updates Mr. Huggins

overhead of the evaluation which was page 27 of Exhibit 433.

The cost/benefit ratios which are the second to bottom line of this evaluation show that the ratios range from .95 against the enhanced plan, to 1.06 against the nuclear Update Plan. And that compares to a range of 1.02 to 1.04 which was shown on Mr. Huggins table.

I don't think it is particularly the differences in numbers that are significant, the real significance is that we still believe that the purchase has approximately break even long-term economics. The reason for that is the changes that tend to reduce the economics are approximately offset by improvements.

The main change reducing economics is that the net transmission cost is now higher, because with lower load growth, the major transmission between Northeastern Ontario and Northwestern Ontario is required later in the no purchase case, and that results in a bigger proportion of that transmission cost being effectively allocate to the purchase.

The change that tends to improve the economics is the more complete evaluation of acid gas reduction benefits which I have already referred to.

Q. All right. I take it that the

original evaluation report included some sensitivity analysis and I ask whether this evaluation has already included that?

[4:00 p.m.]

Yes, the original sensitivity analysis was included in system planning report 686, SP 686, which was Exhibit 434.3. And that included the sensitivity analysis which as part of the transcript undertaking 442.7 has been updated, along with the other re-evaluation. And the summary of the results of that are shown on page 99 of Exhibit 682 which summarizes the sensitivity analysis.

One of the largest sensitivities, and it is now larger than it was in the original evaluation, is with respect to load growth. You will notice that the cost value ratio ranges from .73 to 1.64 or the cost value differences range from minus 769 to plus 970 as you go from upper load growth to lower load growth.

This is something that we expected because the bandwidth has now been widened and you would expect that evaluation of that full bandwidth would therefore show a larger sensitivity.

One other aspect in interpreting these sensitivities is that in some cases we have only shown one side of the sensitivity in the sensitivity

analysis. For instance, we have shown the effect of including the full costs of the Northern Ontario interconnection as a cost of the purchase. And we have done this in a number of cases so that we can see the amount of negative risk that we face if things go the wrong way. It doesn't mean to say that the risk is one sided and that there are not balancing risks on the other side. It is just that we haven't evaluated them.

The transmission benefit which is reduced -- sorry, the transmission cost of the Manitoba Purchase which is higher when you assume that the purchase is going to bear the full costs of the Northern Ontario interconnection is one direction of the sensitivity, but the transmission that is being provided could also be justified earlier than shown in the analysis on its own right if there was to be a for instance rapid growth in load in Northwestern Ontario. So there are other directions that these things can go.

Q. For instance, that kind of benefit that you speak of, there has been no credit taken for that in this analysis. It is only the negative risk that is dealt with?

A. We have shown the negative risk with respect to the Northern Ontario interconnection, the interconnection benefit and the line that says no

emissions credits. And all of those actually have compensating sensitivities on the other side. They are not ones that would hurt and they haven't been evaluated.

Q. Now you have spoken of the full system simulation. Did the re-evaluation include any other methods of evaluating the purchase and if so what did they show?

A. We did include in the transcript undertaking a comparison based on the avoided cost methodology that is used to evaluate demand management and non-utility generation. And that's based on the system incremental costs and the avoided cost methods that we have described, which are applied to demand management, high efficiency cogenerators and renewable non-utility generation.

And if those were to be assumed to be delivering to the bulk electricity system electrical power and energy on the same timing and the same schedule as the purchase, the same energy delivery pattern, then the avoided cost that would be evaluated would be 5.39 cents per kilowatthour and that number is in the transcript undertaking.

The comparable levelized unit energy cost of the purchase is 4.7 cents per kilowatthour and so a

demand management or non-utility generation option with similar characteristics and the same net cost would show a cost/benefit ratio of 4.7 divided by 5.39 which comes out at 0.87.

Now, I should point out that the avoided cost of demand management and non-utility generation includes a 10 per cent preference premium which is not applicable to the purchase; and removing that preference premium increases the cost/benefit ratio to .96.

So, after that adjustment, you can see that the avoided cost methods used for demand management and non-utility generation give similar results to the system simulation that has been used for evaluation of the Manitoba Purchase. In this case it would have been slightly more favourable than the full system simulation method.

You can also turn this around and put it another way, that if the purchase were cancelled and non-utility generation and demand management were purchased at avoided cost, then the total cost to the system would be similar or possibly a little bit higher.

Q. Now, we have talked about a potential surplus developing and I guess the simple question that

arises from that is why do you view the purchase as still being required?

A. I think there are a number of reasons. First of all, it's break-even economics under median load growth, so it's not a significant cost. It protects against the uncertainty of upper load growth and other uncertainties that could cause a need for additional resources.

In addition, it reduces the use of fossil fuels. The total energy associated with the purchase is about 7 terawatthours and this is quite significant if you start to compare it with the amount of fuel that we expect to use in the fossil part of our system. It represents about 25 per cent of the 25 to 30 terawatthours which is the normal energy production of our fossil system.

And so if we didn't have the purchase, then the fossil system would probably have to make up the additional energy and it is saving a significant proportion of the problems associated with fossil fuels and their emissions.

In addition, the Manitoba Purchase gives us access to a renewable energy source. It adds some diversity to the system and there are additional benefits in terms of better system integration which

are associated with the transmission.

Another factor is that these sorts of opportunities don't come along very often. For you to be able to make a purchase such as that from Manitoba, there have to be a combination of a number of circumstances at the same time that would permit such an arrangement to be made. For instance, it must be a situation where Ontario wants to buy. It must be a situation where Manitoba wants to sell. It must also be a situation when the market for Manitoba to sell its energy to customers who are closer to them than we are, such as the U.S. utilities to the south of them, that alternative market must be poor. And in addition to justify the transmission there has to be this long standing need for better integration, which there is, for the better integration of the Northwestern Ontario system into the rest of the system. This combination of circumstances doesn't occur very frequently and such an opportunity might not occur again for some time.

Q. Now based on your judgment, how do the results of the evaluation at this point in time compare to the situation that was discussed in Panel 7.

A. Well, in my judgment, although the cost/benefit ratios that are shown by the evaluation are very similar, the current evaluation is a little

bit less favourable than was discussed in Panel 7. And the reason for that is that with a fuller evaluation of the acid gas control benefits, then one of the benefits that was an intangible benefit outside of the evaluation as discussed by Panel 7 has now become a benefit that is valued and included inside the evaluation. So there is one less unquantified benefit.

However, we do believe that this current evaluation remains positive, that the break-even economics, together with important additional benefits in terms of improved system integration, benefits that were discussed at greater length by Panel 7, do provide an evaluation that overall is very positive.

Q. Now Dr. Long, I want you to come back please and describe for us the financial impacts associated with the re-evaluation of the Manitoba Purchase.

DR. LONG: A. Yes. To begin, I would say that the financial impacts included in re-evaluation are rather like the results of the economic evaluation show results which are quite similar to those in the initial evaluation.

In describing these impacts, I will be referring to some of the factors that I mentioned in my testimony yesterday and these were the factors

associated with the purchase that influence the rate borrowing impacts.

The next overhead which is page 100 in your package shows the projected rate impact associated with the purchase for both the update nuclear and update fossil plans under the median load growth. What this chart shows is the difference in price level between a case with the purchase to one without the purchase.

This indicates that over the period from about 2000 to 2010, electricity prices under the case with the purchase are expected to be about 3 per cent higher. And we can see the beginning of this trend at the end of the projection. Beyond around 2011 rates under the purchase case are expected to be lower.

Now, the higher initial rates associated with the purchase are due to the front end loading of the purchase price combined with the impact of the fixed charges associated with the transmission needed to accommodate the purchase.

While the longer term rate impacts have not been analyzed in detail, we are confident that they will be more favourable under the Manitoba Purchase case. What I mean by that is that rates with the Manitoba Purchase are expected to be lower.

Q. And that I take it is a function of the lower -- in large measure a function of the lower multiplier in the latter part of the contract?

A. There are I guess basically two reasons why we are confident that this is the case. The first, as you mentioned, is due to the purchase price multiplier. As indicated on the overhead chart, in the longer term this multiplier is a factor of .75 whereas in the early part of the contract period it's 1.3 dropping to 1.0 in the period around 2005. And this is expected to result in a lower rate impact beyond about 2011.

Also in this period, the price impact of the transmission associated with the purchase is expected to reduce. You will recall that I mentioned yesterday that the fixed charges associated with the transmission decline with time. That's one factor.

Another factor is that much of the transmission associated with the purchase - and I have indicated on the chart sort of rough in-service dates of major portions of that transmission - much of that transmission is in fact advanced in the purchase case; that is, much of it will be required under the no purchase case only at a later date and this will mean that the rate impact due to transmission will

eventually be lower under the Manitoba Purchase case. In the period beyond 2010 also the deferral of major supply due to the purchase will also contribute to lower rates.

The next overhead, which is page 101 in now package shows the borrowing impacts associated with the purchase. And very quickly what this shows is that in the mid-1990s to around the mid-2000s borrowings are somewhat higher due to the purchase, and this is basically to fund the construction of the transmission. However, from the mid-2000 onwards, there is expected to be a significant reduction in borrowing requirements mainly due to the deferral of supply.

Q. Thank you. Now, Mr. Dalziel, I want to come back to you and deal with the circumstances as you see them should the approvals which are being requested not be granted, and I take it you have looked at cases without the Manitoba Purchase, that is, through denial of the transmission that's requested and the non-approval the hydraulic option?

MR. DALZIEL: A. Yes, we have looked at three cases, one for each of the lower, median and upper load forecast conditions, and we have called these series of cases the no approvals cases. They are described in Exhibit 646 under attachment E and they

essentially exclude the Manitoba Purchase with the exception of the 200 megawatt portion that is not reliant on the Manitoba Purchase transmission. And it also then excludes the hydraulic option.

The cases use a combination of CANDU and IGCC for base load and CTUs for peak load. And where it is appropriate, we have used surplus management assumptions. That's mostly under the median and the lower load forecast cases. We have looked at some selected characteristics of these cases, namely, the energy simulations, certain emission characteristics, and costs.

Q. Could you describe the changes in the new major supply requirements that you saw as resulting should approvals be denied.

A. Page 102 in Exhibit 682 illustrates the impact under median load forecast, the additional major supply capacity requirements under median load forecast. And essentially relative to the median load forecast, the update nuclear median, the amounts of capacity is increased by about 2,700 megawatts.

If we look then at the major supply requirements in the next figure, which is 103, this is showing then with the no approvals cases what the required major supply capacity is under the lower,

median and upper load forecast.

One of the first things we see is that under the lower load forecast, right at the tail end of the plan period, there now is a small requirement for new major supply, that was otherwise not needed because of the Manitoba Purchase and hydraulic options.

We also note under the upper load forecast that around the year 2000, earlier that requirement used to dip back down towards zero; now it remains up around 3-, 4,000 megawatts and continues to increase from that time.

To describe these cases, I am going to now compare the no approvals upper to the previous upper limits that I described that included the approvals. We will look at the no approvals median to the update nuclear with surplus management and we will look at the no approvals lower to the other lower case that I described earlier.

Page 104 of Exhibit 682 looks at the median load forecast condition and here we are looking at the changes in the capacity that takes place in the no approvals case relative to the update nuclear and I am just summarizing it by the end of the plan period.

The demand reducing options are the same. They are at their forecast level and they are not

managed under this median load forecast case. The purchase NUGs are the same by the end but they are managed but to a lesser extent compared to the update nuclear under median load forecast.

There is no Manitoba Purchase. There is no hydraulic option. And that capacity then is made up by additional combustion turbine units. The amount at CANDU is the same in this case as the update nuclear under median load forecast.

We see that the total amount of capacity installed in this case is higher by about 700 megawatts and that's due to the degree to which the reserve margin again is met in the final year of the plan. And as it turns out it is 3 per cent higher in this no approvals case than it is under the update nuclear.

Certain acid gas control measures have also been advanced by one to three years in this case.

Now, we have looked at the energy production characteristics of this case and I'm not going to take you into the details of it. Essentially you will recall that the Manitoba Purchase is producing about 7 terawatthours and the hydraulic option is providing an additional 3 terawatthours. So essentially there is 10 terawatthours of energy that needs to be made up over a good portion of the plan

period.

And when we look into the details of the energy production results, we find that the existing fossil system is working harder to the extent of about 7 terawatthours and that the new fossil, those CTUs, are providing an additional 3 terawatthours by the end of the plan period.

If I carry on and comparing then the no approvals upper case to the earlier upper case that I described, there is no need to apply any surplus management assumptions under this load forecast condition, so the demand reducing options and the purchase NUGs are the same as under no surplus management.

There is no Manitoba Purchase, no hydraulics, and capacity is being made up here by CTUs. It was judged that some intermediate load under this condition could be covered by a combined-cycle facility running on gas. There is the same quantity of IGCC plant and relative to the update upper with approvals, there is one more CANDU unit.

[4:25 p.m.]

Here the total amount of generation is lower by 115 megawatts and again that's due to the degree to which the planning reserve margin target is

actually met.

Again, there is 10 terawatthours of energy that must be made up, and again we find that it is largely the fossil options that are making up the 10 terawatthours.

I have provided a figure to compare this page 106, if we could turn to that in Exhibit 682. I am showing this because in this CTUs in the combined-cycle facility here we have found that these facilities would be operating at high enough capacity factors where they would most likely be running on natural gas. And these two figures then are comparing the natural gas energy consumption, the top graph is with approvals and the bottom one is the case with no approvals, and essentially we see that on balance by the end of the plan period there is about 10 terawatthours more of energy being produced from natural gas.

You will recall that under the earlier upper load forecast case that I mentioned, that perhaps two to four terawatthours of gas might actually be used in the CTUs. So the incremental amount of gas used here is perhaps the in order of 6 to 8 terawatthours.

Under the lower load forecast condition, page 107 illustrates the comparison then of the no

approvals lower to the other lower case that I described. We do have surplus management assumptions built into this case because it is a lower load forecast case. But by the end of the plan period, the demand reducing options and the purchase NUGs are at their forecast level.

Again, there is no Manitoba Purchase, there is no hydraulic, and the lost capacity is being made up by CTUs.

Again, this case, the no approvals case has about 540 megawatts less capacity installed, and again that's due to the degree to which the planning reserve margin is actually matched in the last year.

Again, by the end of the plan period there is 10 terawatthours of energy that needs to be made up, and once again we find that it is the fossil options that are making up that energy, and in this case it's a combination of the purchase NUGs, the existing fossil system and the new fossil facilities.

So to the extent overall that fossil fuels are used, there is a little less diversity in terms of a source of energy under the no approvals case, but in general the use of fossil fuels increases.

Q. All right. And how do the costs compare across these range of cases?

A. Well, I will first focus on the median and that cost summary or comparison is provided on page 108 of Exhibit 682.

What we are looking at then are the costs of the no approvals case, minus the costs of the approvals case, and the cost categories on the left-hand side are the same cost categories that we had in our earlier figures that summarized the costs. Again, further details on this are available in the attachments to Exhibit 646.

Just bringing to your attention a couple of items then, is that the fossil costs under the median case are higher, in that there are the additional 3,000 megawatts of CTUs being added.

Under the emission controls and other costs for existing generation category there is a net reduction in cost by $138 million there. That's assuming a repayment from the government for no approvals associated with the Smoky Falls development of $252 million, but there is also advanced acid gas controls and that's adding the cost of about $114 million, so the net effect is 138.

Q. But this analysis does assume the arrangements for the Smoky Falls development are followed through and in this circumstance the $252

million flows back to Ontario Hydro from the government?

A. Yes, that's correct.

Q. Okay.

A. Then just moving down the column there would be cost savings because of the no Manitoba Purchase and the hydraulic option being excluded. And the increase costs associated with the load reducing options and the purchase NUGs are a result of the surplus management assumptions, that there are more of these options brought into the plan sooner in comparison to the update nuclear under median load forecast. There are changes in the transmission costs because there is no transmission to incorporate the Manitoba Purchase, and other timing effects associated with inter-area transmission.

There are lower distribution costs because there is increased demand management earlier in the plan period.

Then counter-balancing those cost savings then are the increased costs associated with fuel, and again, relying more on fossil fuels is the main reason for that. And then at the bottom then we have the net cost difference between the no approvals and the approvals case, and we find then that the no approvals

case is lower in cost by $143 million present value.

I will show one more figure to illustrate a cost comparison, and that's page 109 of Exhibit 682. This is now comparing the costs, again we are looking at the no approvals upper, to the earlier upper, the median that I just summarized is in the middle and on the far left-hand side is the comparison of the lower load forecast cases.

So to the extent that lower load forecast develops, there is a deterioration in the advantage of having approvals for the Manitoba Purchase and hydraulic option. Under median load forecast we see that the costs are generally similar, comparable. And then to the extent that there is higher growth in demand, then there is a cost of advantage for the approvals, the options associated with approvals of the Manitoba Purchase and the hydraulic option.

Q. All right. I would like to turn then to you Ms. Howes and deal with these comparisons, deal with the environmental implications associated with this comparison, and ask you to work us through your usual set of charts dealing with the various natural environmental factors.

MS. HOWES: A. Okay. I will be comparing the update nuclear with the no approvals, and

all of the figures that I will be referring to are in Exhibit 452G. But if we can show figure 110, just to be clear what we are talking about.

Again here we are looking at on these bar charts, the first two bars, the first one is the update nuclear, the second one is the no approvals. You can see when you look at hydraulic, there is less hydraulic in the no approvals as Mr. Dalziel has mentioned, in purchases there is no Manitoba Purchase.

The energy is made up in terms of greater use of coal in the existing system and through oil-fired CTUs and some additional NUGs.

The second figure is figure 111. On this particular chart you should focus on the update nuclear which is the line with the little black square and the no approvals as the line with the cross. You will see that to the year 2005 there is no difference in SO(2) emissions between these two plans. Beyond that period, the no approvals plan has slightly lower SO(2) emissions and this is because of the advancement of scrubbers.

If we could flip to the next one which figure 112, it's looking at total NOx emissions.

Total NOx emissions, again we are looking at the update nuclear and no approvals plan. They are

very similar over the planning period. You can see the slight increase in NOx emissions due to the heavy use of the fossil system, but generally I would have to say they are very similar.

Relative to the dotted line on this particular graph which represents the possible targets that I have mentioned previously, both the no approvals and the update nuclear plan are well below the possible regulation limit.

If I can turn to the next one, which is figure 113, that is total CO(2) production. When one compares update nuclear with no approvals to the year 2005, there is little difference between the plans. Beyond the year 2005 there are higher CO(2) emissions with the no approvals plan. As I have said, this is due to the increased use of the fossil system as well as the oil-fired CTUs.

The crossover point with the dotted line, which is the possible limit line, occurs in about the year 2010.

So beyond that point, the no approvals case, there would be some excedance of a possible limit for CO(2).

Trace elements and particulate emissions are very similar between the cases. Water use is

similar between the two plans. Cooling water requirement is slightly higher for the no approvals case because of the increased use of the existing fossil system. Waste volumes are similar for both plans over the period, that's for both conventional waste and radioactive waste. Radioactive emissions or radionuclides are similar between the two plans; however, there is some difference in resource use, and if we could turn to figure 115.

What this particular figure illustrates is the -- 114.

114 illustrates the additional use of coal for the existing fossil system.

115 illustrates the additional use of oil in the oil-fired CTUs that Mr. Dalziel had mentioned.

Uranium consumption is the same between the two plans and neither plan consumes natural gas.

Land use is also very similar between the two plans.

So, in summary, I would have to say that from a natural environmental point of view there was a lot of similarity between the two plans, however relative to the update nuclear, the no approvals plan has higher CO(2) and higher coal and oil use, it does however have lower SO(2) emissions.

Q. Dr. Tennyson, turning to you. How would the no approvals case compare to the median Update Plans?

DR. TENNYSON: A. There would be less employment and regional economic development in the short-term, but they would be similar late in the planning period.

In addition there would be fewer potential significant community local community impacts until around the year 2000, with no new Ontario Hydro facilities.

In terms of the social acceptance of this case, the limited capability to respond to higher than median load growth may be a concern because, as I have indicated earlier, reliable electricity is still important to many members of the public and is also seen by them as important for the provincial economy.

For the distribution of risks and benefits, until late in the planning period most Ontarians would share the risks and benefits of this case.

Q. And could you, Dr. Long, then summarize the financial assessment of that no approvals case?

DR. LONG: A. As for the environmental

impacts, the corporate financial impacts associated with the no approvals case has only been assessed against the update nuclear case for median load growth. And the results that I am going to describe are discussed in paragraph 38 of the witness statement which is Exhibit 646.

The next overhead, which is page 116 in your package, shows the projected rate impact associated with the no approvals case, and what this chart shows is the difference in electricity prices between the no approvals case and the update nuclear case. Specifically it's the no approvals case minus the update nuclear case. What this shows is that over much of this period out to 2010 or 11, rates are lower by up to about 3 per cent under the no approvals case. After that period we can see they start to go higher and they are expected to stay higher beyond that period.

The initial lower rate impact under the no approvals case is due to not having the front end loading accounting cost associated with a hydroelectric program as well as that with the Manitoba Purchase, and this is partially offset by the need to advance some emission control equipment.

These initial impacts are then expected

to decline, and combined with the cost of replacing capacity with the CTUs that Mr. Dalziel described, this is expected to result in a rate outlook under the no approvals case, which is eventually going to be higher than under the update cases.

Our confidence in that outlook is very similar to what I have described under the description of the impact of the Manitoba Purchase, much of the impact on rates under the no approvals case is in fact due to the Manitoba Purchase.

Q. And with respect to borrowing?

A. Yes, the next chart, page 117 in your package, shows the impact of the no approvals case on borrowing. And once again, this shows a similar picture to that under the discussion of the Manitoba Purchase.

Under the no approvals case we have generally lower borrowings until around the mid-2000s, and these are due to not having to fund the hydroelectric program, the transmission associated with the Manitoba Purchase, and partially offset by the need to fund the additional CTUs, the replacement capacity.

Beyond the period shown, the borrowing is expected to be higher under the no approvals case due to the need to fund further additional supply.

On a cumulative basis, the borrowings over the 20-year period shown were about $4 billion lower than under the update nuclear case, but of course Hydro has a similar reduction in assets. As well, this overall reduction in borrowing is expected to be eliminated beyond about 2010 as additional supply is put in place.

Q. Now, Mr. Snelson, we have seen somewhat of a contrast here between the cost information described by Mr. Dalziel and the rate impacts that have been described by Dr. Long. How do you go about reconciling those differences?

MR. SNELSON: A. Well, the cost information shows about a break-even situation, the rate impacts show higher rates with no approvals within the first 10 years or so and lower rates beyond.

This kind of situation is not something that's unexpected and higher rates in early years with lower rates in later years should not be considered a barrier to worthwhile investments.

This is the sort of situation that you experience with any long-lived capital intensive investment. And the accounting unit energy costs that were displayed in Panel 3 showed the effect that accounting methodologies tend to load more of the costs

into the front end of the project than later.

If we were in the situation where we are not going to proceed with any options that would temporary increase electricity rates, then we would effectively be living off past investments, living off the investments that were being made by previous generations of customers without adding to the infrastructure to the benefit of future generations of customers. And effectively, the level of investment in the electricity system, electricity infrastructure would be winding down.

That is not to say that there are not circumstances under which rate impacts may limit the level of investment for the future. As in many of the things we have to have to maintain a balance. What is affordable in the short-term has to be balanced with what is prudent to provide for the future.

Dr. Long has indicated that through of the planning period the rates tend to increase at about the inflation rate from 1994 to about 2010.

[4:43 p.m.]

And this is the time period through which we would be acquiring the new capital investments associated with the resources we are seeking approval of. And the fact that the rates in that period

increase at no more than the rate of inflation does suggest that the financial impacts are manageable and that we can therefore afford the rate impacts for a short while of the hydraulic and the transmission associated with the Manitoba Purchase.

Q. Now how do the update plans compare to these no approval cases in your judgment from a broad planning perspective?

A. Well, I think it is clear that the no approvals case is not a disaster scenario. It is not a scenario where if we don't get these approvals, then the lights are going to go out. And in some ways that scenario does show that it can be manageable from a number of perspectives and we have to bear in mind that that is provided many other elements of our plan meet challenging targets.

However, it is not satisfactory in three important areas.

Q. That is the no approvals cases in your view?

A. The no approvals cases, not satisfactory in the areas of diversity, flexibility, and policy considerations.

Q. Can you deal first with your concerns in the diversity area.

A. The update plans that we have can be broadly summarized as relying on three types of new energy resources in addition to the existing system: efficiency, renewable energy, and natural gas.

In the category of efficiency, I am including electricity efficiency improvements of the demand management program, the fuel switching of the demand management program, which has some element of efficiency associated with it, and the cogeneration of the non-utility generation program which also improves efficiency.

In the renewable energy, there is some contribution from renewable non-utility generation. But by far and away the largest part of the renewable energy we are relying upon is the 7 terawatthours from the Manitoba Purchase and about 3 or 3-1/2 terawatthours from the hydroelectric program. So, the approvals that we are seeking cover most of the renewable energy contribution to the plan.

Under the category of natural gas, there are quite a variety of options that are included there. Most of the cogeneration and fuel switching, which I have categorized as efficiency, can also be categorized as natural gas because they would mostly likely be switching to natural gas or natural gas fuel

cogeneration.

In addition, most of the options that we are relying upon for flexibility would be natural gas fired. That includes major supply non-utility generation, Ontario Hydro combustion turbine units and combined cycle units, and gas in existing plants as a fallback measure to reduce emissions if we can't reduce emissions by scrubbing coal and low sulphur coal.

So, these three main supports of the plan we believe are weakened if any one of them is withdrawn. And one of the characteristics of our plans is that any shortfall tends to be made up in the natural gas and existing fossil components, and I have shown that on the next overhead which is page 118 of Exhibit 682.

As I have said, if there are no approvals, then there is little renewable energy left and the energy will be made up from fossil fuels from either new natural gas options or more fossil fuel in existing plant.

Similarly, uncertainties in demand management or in load also affect natural gas and the existing system fossil energy production. Mr. Dalziel has shown that with upper load growth, the fossil energy from the Ontario Hydro system would be about 80

terawatthours and that's unprecedented. It is about two to three times anything that we have experienced before.

Natural gas dependence - and I am including here all options that rely upon natural gas and not just Ontario Hydro, so that includes the non-utility generation and fuel switching - natural gas dependence on upper load growth can rise to about 40 terawatthours, which is about 1-1/2 times what we produce from coal under normal circumstances.

No approvals makes this situation worse by about another 10 terawatthours. So without approvals, the diversity of new options in the plan is relatively poor. We would end up with mostly efficiency, which is good, and natural gas, but of course the proportion of natural gas greatly increases with higher growth and with higher anything else that tends to increase the need for new resources.

Q. Now the second matter you raised was flexibility. Can you review the issues related to that factor.

A. Yes, I think this is a very simple issue and that is that the update plan by relying upon the demand management non-utility generation, the hydroelectric and the purchase has, we believe,

sufficient options to be capable of meeting a large part of the upper load growth and we have said this several times.

If the approvals were denied, then we lose 2,400 to 2,800 megawatts. That's 1,000 megawatts of Manitoba Purchase and 14 to 1800 megawatts of hydraulic. We lose that amount of capacity. And our judgment would be that planning around the median would not be satisfactory and that we would probably be seeking major supply approvals if we did not have those approvals to maintain flexibility.

Q. Can you deal with the policy matters that you referred to.

A. The hydroelectric program and the Manitoba Purchase are both supported by specific Ontario provincial government policy. There were the new energy directions which were issued in November 1990 which gave us direction to seek environmental approval for the hydraulic options, and I will quote the appropriate paragraph:

> The government will help ensure that Ontario's electricity needs are met by requesting Ontario Hydro to give priority to the early environmental assessment hydroelectric projects at new and

existing sites and for transmission facilities to bring electricity from Manitoba.

And in addition, we have had an Order in Council with respect to Patten Post in June of 1991.

So that's on a general level. But if the approved range of hydroelectric capacity were to be zero, then we believe it's unlikely that any significant hydroelectric options would proceed, apart from a few non-utility generation projects, that Ontario Hydro would not be proceeding with hydroelectric options for quite some years to come.

And there were specific opportunities that would be lost. For example, Mr. Dalziel has referred to the payment that would be presumed from the provincial government with respect to Smoky Falls if there were to be no approval that would cover Smoky Falls, and that's a rather complicated situation related to the Kapuskasing paper mill, the redevelopment of Smoky Falls and the redevelopment of the other hydroelectric plants on that river.

And the government has arranged to keep the paper mill operating partly based on the value of redeveloping Mattagami. If the plant can't be redeveloped, then the government is obliged to pay

Ontario Hydro the sum of money that Mr. Dalziel referred to, which is our estimate of the cost of buying Smoky Falls in excess of its value; that is, in excess of its value if it cannot be redeveloped. Now that is not a cost to Ontario Hydro and in fact is shown in the economics as a credit to the no approvals case, but it is a cost to the people of Ontario.

Another specific opportunity that would be lost if there were to be no hydroelectric approvals is with respect to the waters at Niagara. Obviously if we can't proceed with the redevelopment, then we don't make full and efficient use of Canada's share of water, we have lost capacity and energy, and that is being evaluated. But in addition there are risks that there will be a less favourable water treaty with the Americans. The international treaty is to be renegotiated around the turn of the century and the Canadian negotiating position is weakened if Canada can't use its share of the water efficiently and the Americans can.

Continuing. We have been asked to accelerate the development of Patten Post for certain policy reasons under the provincial Order in Council; and if there were to be no hydroelectric approval, then that wouldn't happen and the economic activity in the

area that the government is seeking wouldn't take place. And that is intended, we believe, to reduce some of the negative impacts of the reduction in employment at Elliot Lake in the mines.

So just to summarize on a very broad perspective the case with approvals and without approvals. The costs are about equal and that's something we expected. We knew that the Manitoba Purchase had a cost/benefit ratio of course close to 1. We knew that the hydroelectric options had cost/benefit ratios that were close to 1. The diversity without approvals is not very good. We believe there is too much reliance on fossil fuels, particularly gas, particularly if load growth is high or less than expected or if there is less than expected demand management.

We would need additional environmental controls for air emissions. The flexibility is poor without major supply approvals and we believe that we would not be responding to the policy thrusts from the provincial government and there would be specific lost opportunities.

MR. B. CAMPBELL: Mr. Chairman, I have approximately ten minutes. It's your call.

---Off the record discussion.

THE CHAIRMAN: I think we will take the ten minutes on Monday morning.

MR. B. CAMPBELL: Thank you.

THE CHAIRMAN: And then we will follow with Mr. Mark; is that correct?

MR. MARK: That's right, Mr. Chairman.

THE CHAIRMAN: We may have some questions also to ask.

Monday morning at ten o'clock.

THE REGISTRAR: This hearing is adjourned until Monday morning next at ten o'clock.

---Whereupon the hearing was adjourned at 4:55 p.m., to be reconvened on Monday, May 25, 1992, at 10:00 a.m.